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Petroleum Reservoir Rock and Fluid Properties

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This course was adapted from the Henry L. Doherty Series, Book “Elements of Petroleum Reservoirs” by Norman J. Clark, Chapters 1 through 4, which is in the public domain.

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Chapter 1: How Petroleum Was Formed and How It Gathered into Reservoirs

The Earth at Dawn

The history of the origin and accumulation of petroleum is written in geologic signs found in the formations of the earth that were laid down throughout the earth's existence. The story of petroleum or "rock oil" transcends the earth's geologic time; therefore, the entire story includes all chapters of the earth's existence.

Scientists and astronomers do not agree on how the earth was formed. Some propose that the earth, as well as other planets of our sun, was formed as a result of a collision of another sun with our sun in which a great splash of molten rock was thrown into space. They claim that this great mass of rock splattered into many small masses that separated and became planets, planetoids, comets, and other bodies in space. The earth thus was formed as one of these planets that revolves about our sun. Other scientists propose that a great nebula of cosmic dust swirled around a vortex, particles, forming the nebula condensed by attractive gravitation and formed the sun. Outer rings of particles coalesced and turned into the individual planets of our universe.

Although the question of how the earth was formed may always be the subject of speculation, the question of when the earth was formed is thought to be well established. Radio-active materials decay in a known period of time, and the age of rocks containing these materials can be determined by calculating current degrees of the decay process.

Whether the earth started as a gaseous mass or as molten rock, it passed through a molten stage and cooled sufficiently at the surface to form solid rock masses. According to scientists, these first rock masses formed some four or five billion years ago.

During a period of further cooling, the earth shrank. The crust buckled and warped like the skin of a drying prune. Gaseous materials and steam spewed forth from the earth, and after further evolution and cooling, atmosphere and oceans were formed. Continents took shape from the solidified rock, and annual rhythmic climatic changes commenced.

Mountains are formed

The oceans covering the major part of the earth's surface are well known for their currents. Although several factors cause these currents, earth motion is recognized as a major reason that they continue. Just as this motion propels the great water basins, it is also believed to cause currents to take place in the molten rock of the earth's interior.

Although much of the warping and other crustal movements of the earth were at one time caused by the earth shrinkage through cooling, it appears that during most of the earth's geologic past

crustal movements were caused by plastic flow of inner molten rock. These movements caused great mountain ranges to rise and great seas to form (Fig.1). Age after geologic age saw mountains changing positions to the extent that sea floors became mountains and mountains submerged into the seas.

While mountains protruded and fell away beneath the sea, a number of natural cyclic processes took place throughout the ages. Movement of shorelines in this process formed the stage on which the drama of the origin of petroleum was enacted.

The movement in the shoreline of the sea across Texas over the last 250-million-year period is shown in Figs. 2, 3 and 4.

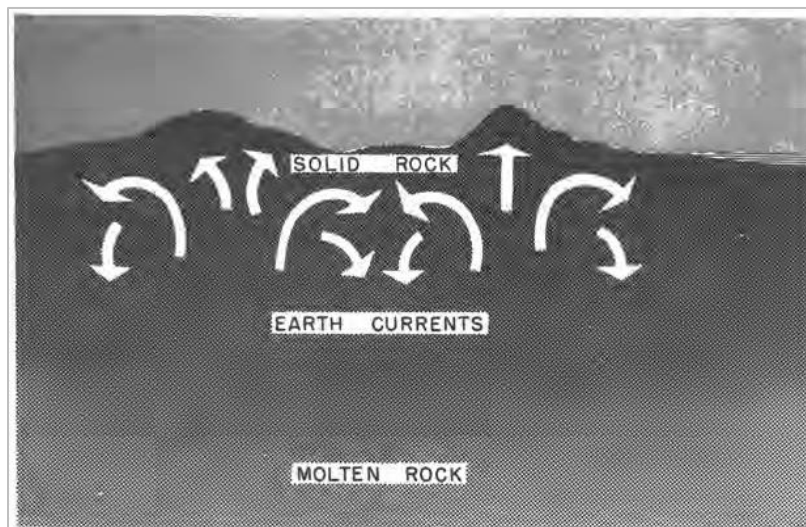


Fig.1. Mountain formed by earth currents.

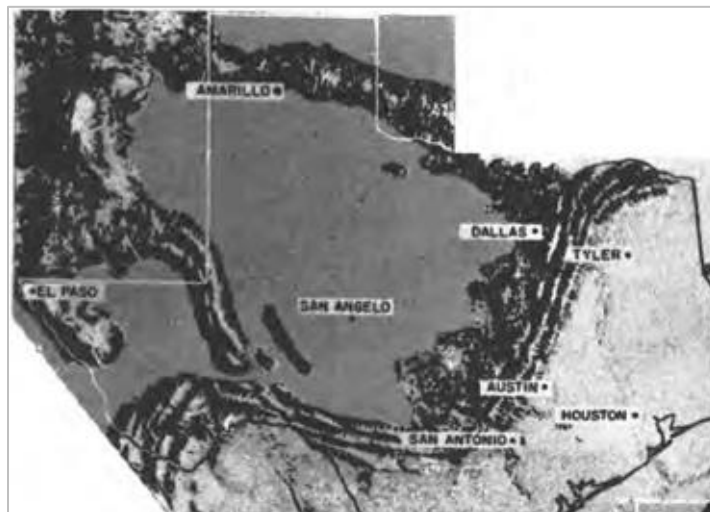


Fig.2. Texas 250 million years ago.

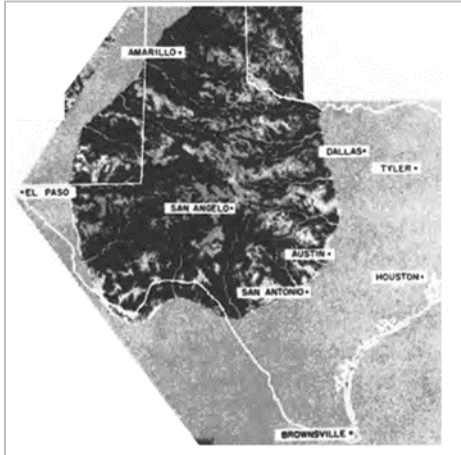


Fig.3. Texas 100 million years ago.

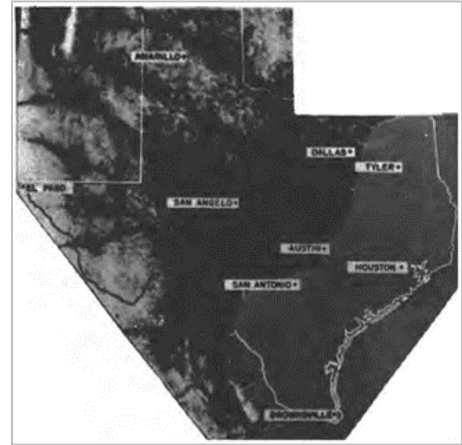


Fig.4. Texas 50 million years ago.

Mountains are Eroded and Sediments Deposited in the Seas

Elements of the weather, wind, temperature change, and rain have been and are at all times eating away at the mountains and fields. The rock surface is under a continuous process of decay, forming the soil in which vegetation grows. Particles of rock, or the rock cover of soil, are continuously sloughing down slopes to lower levels. Tiny rills with their loads of sediment join into brooks which run into rivers. The greater the slope of the water course, the faster the water runs and the larger will be the size of the particles of sediments that water will transport; therefore, the greater will be the load of sediments carried by the water. The results of a long geologic period of erosion on a mountainous region are illustrated in Fig. 5.



Fig.5. Mature erosion in a mountain region.

Laden with the products of erosion, mud, silt, sand, and gravel, the river runs into the sea where a new process, that of deposition, takes place.

Products of erosion thus transported to the seas are deposited as soon as the water becomes sufficiently calm to permit the particles to drop to the bottom. The gravels may have come to rest on the river bottom far upstream, perhaps at the foot of the mountain, or downstream, depending upon the size and weight of the particles and the velocity of the water. The sands are deposited as offshore sand bars or at the river's mouth as deltas where turbulent wave action carries and distributes the sand particles along the shore (Fig. 6). Silts and muds, being easier to retain in suspension in the water, are carried out to the depths of the sea where they are gently laid down in the calm water far from the shoreline. Advancing and receding movements of shorelines, together with deposits of sands and silts at different points out in the sea, result in separate beds of sands and silts (Figs. 7 and 8).



Fig. 6. Model showing deposition of sand near the river mouth as deltas and along the seashore as sand bars.
(Reprinted from *THE EARTH'S CRUST* by L. Dudley Stamp, Crown Publishers, Inc.)

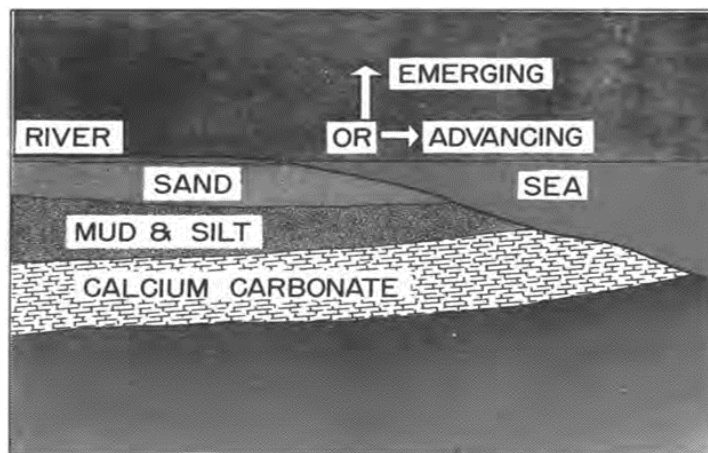


Fig. 7. Beds formed by emerging or advancing shoreline.

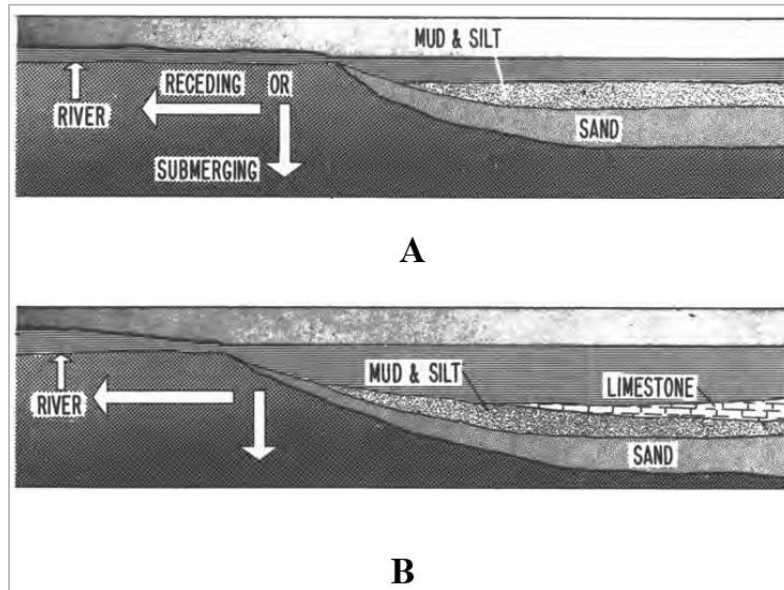


Fig. 8. Beds formed by submerging or receding shoreline.

Petroleum Begins to Form

Although petroleum is known to occur in sediments laid down during all geologic ages, there are many theories concerning its origin.

To study what happened in the dim geologic past, an investigation must be made of what is happening in nature today. The organic theory of the origin of petroleum appears to be the most appropriate explanation based on what is taking place now. This theory conceives that the rivers which carried masses of sediments to the seas also carried great quantities of microscopic plant and animal life. These, together with great volumes of plankton or tiny plant and animal life living in the sea water, settled to the bottom of the sea (Fig. 9). Their remains, covered by sand and silt and sealed from decay, were decomposed by temperature, pressure and bacteria into many hydrocarbon compounds, the mixture of which we know today as petroleum. Proof for the validity of the organic theory stems from the fact that this same process is occurring on a vast scale in contemporary marine deposits.

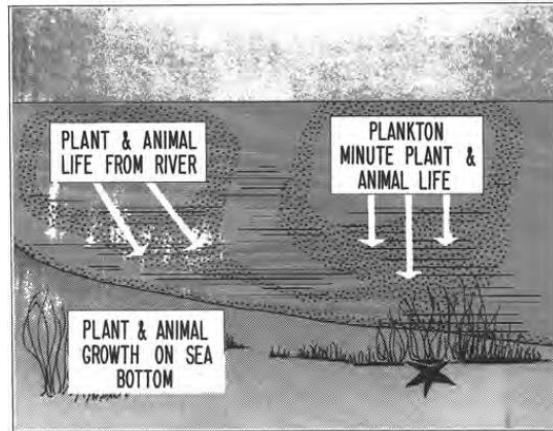


Fig. 9. Sources of organic material.

Structures Form and Sediments Change into Rock

With the passage of countless centuries, beds of sands and muds became removed from directly beneath the sea because the land raised, and the seas retreated. Stresses from the continual shift of the earth's sedimentary crust further compacted the layers of sediments and bent, twisted, broke, and further deformed them into many sizes and structural shapes (Fig. 10).

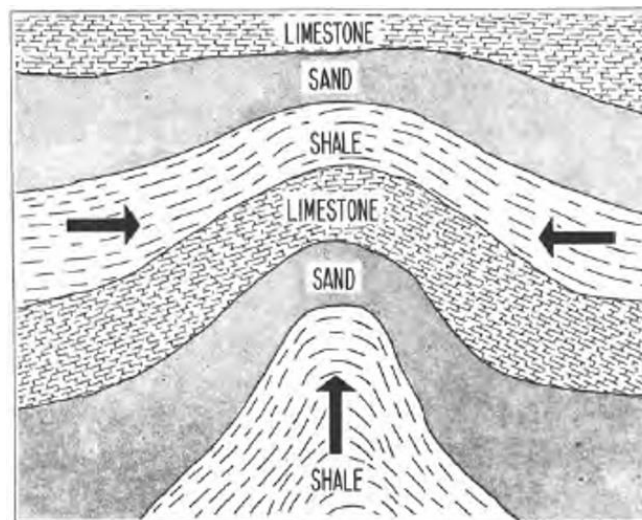


Fig. 10. Forces of compaction and deformation of beds.

Continuous sedimentation with the moving shoreline buried the earlier deposits under countless tons of other sediments. Great pressure from this overburden tended to squeeze, deform, and compact the older layers of sediments. Muds and silts laid down in deep calm sea water were compacted into shales, and then, with geologic time, into slates (Fig. 11). Sands laid down in swift-moving sea waters were cemented by deposition of minerals and clays from the water and compacted into porous sandstones (Fig. 12). In some areas, calcium carbonates were laid down in clear waters by precipitation of this mineral from the water or by formation of reefs and beds of the shell remains of sea life.

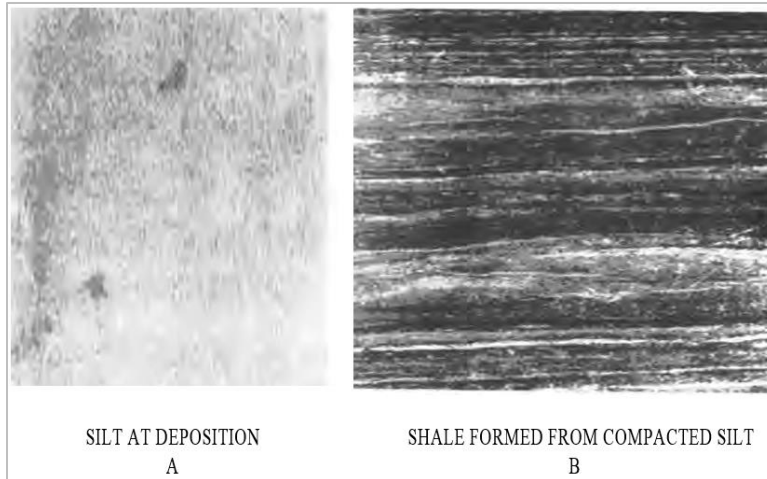


Fig.11. *Compaction changes silt to shale.*

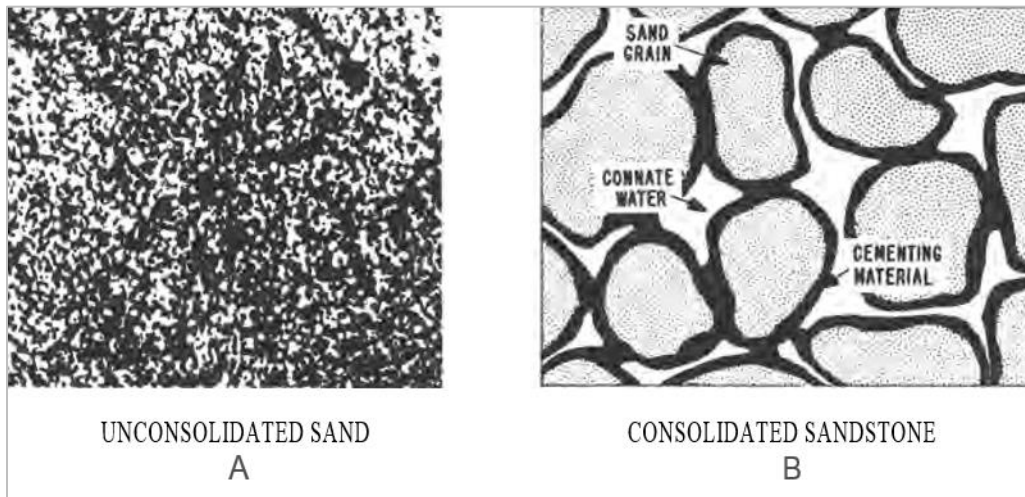


Fig. 12. *Compaction and cementation change unconsolidated sand to consolidated sandstone.*

Subsequent earth movements caused these beds, in the presence of mineral-bearing waters, to become compacted into beds of limestone rock. In many cases, these beds, because of their hardness and brittleness, became jointed and fractured under the great earth stresses involved. Percolation of water in the existing pore spaces, joints and fractures of the limestone beds caused these pore spaces to be enlarged into "vugs" or "caverns" by solution (Fig. 13).

Other waters, carrying mineral concentrations through limestone beds, might fill either the original pore spaces or the solution pore spaces by precipitation. This process is called "secondary deposition".

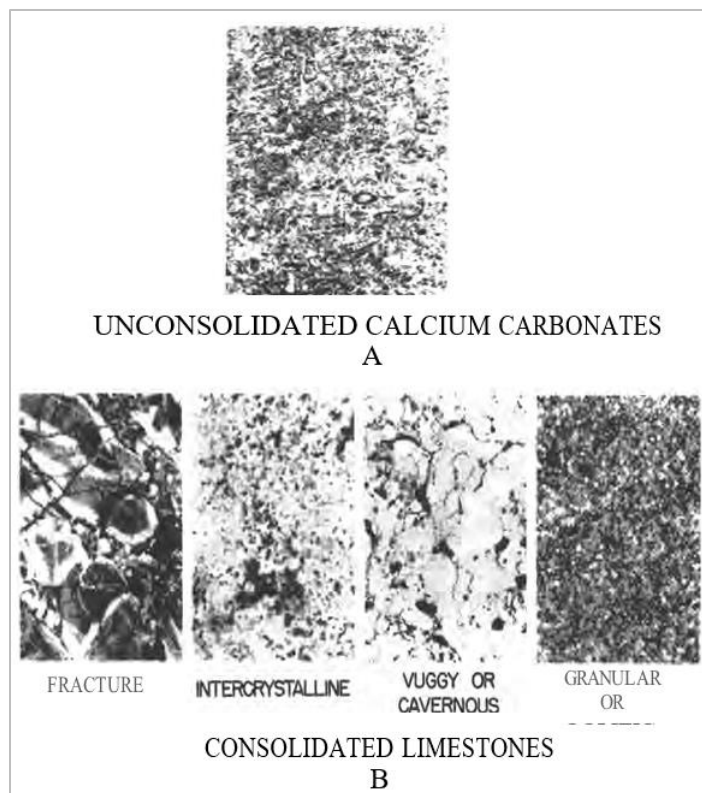


Fig. 13. *Unconsolidated limestone material at time of deposition and various types of consolidated limestones*

Petroleum Migrates and Accumulates in Reservoirs

It is not known whether petroleum in the form of oil or gas moved over great or only short distances before accumulating into deposits as we know them today. Neither is it known whether petroleum components were dissolved in the water of the rock or existed as free hydrocarbon mixtures side-by-side with the water in the rock pore space.

The latest belief, however, is that petroleum compounds originated both in the sands and muds and that rock compaction squeezed them from these source beds into the pore spaces of the layers of sands and carbonates where deposits of oil and gas are located today. Being lighter than the adjacent water, the oil and gas floated upward through the tiny tortuous pore channels in the sand until stopped by the overlying dense rock layers. There the oil and gas could move no further. Sand or limestone rock strata having connected pore channels through which fluids-oil, gas or water can move are said to be “permeable”, or to have “permeability”. Rock strata which do not contain connected pore channels and therefore will not permit fluid movement are said to be impermeable or to have no permeability.

A permeable bed, containing oil and gas in its pore channels, and an overlying bed, which prevents further movement of oil and gas, combine to form a trap. Such a trap can result from a structural condition (flatbed bent upward) or from a strati-graphic condition (lens of permeable rock within an impermeable bed). That portion of a trap in which oil or gas is stored in nature has now come to be referred to generally as a petroleum "reservoir". Often in the past a reservoir has been erroneously referred to as a "pool" of oil because it was thought that oil occurred underground as

a lake. Size of a reservoir depends upon size of the trap and how much petroleum is present to accumulate. Many reservoirs are of limited size because the trap was not large enough to contain all petroleum available, while many others are limited because the originally available petroleum was insufficient to fill the trap. In the latter case, the oil and gas reservoir only partially occupy the trap and water fills the remainder.

Types and Shapes of Reservoirs

Many proposals have been made to classify the different physical shapes of petroleum reservoirs that have been discovered; however, the simplest means of such classification is perhaps a grouping according to the geologic features causing their occurrence. These features are (1) structural folding, (2) structure with faulting, (3) structure with an unconformity, (4) structure caused by some deep-seated movement of earth materials such as salt domes or serpentine plugs, (5) changes in permeability within a formation and (6) combinations of two or more of the foregoing.

Reservoirs formed in folded strata usually result in domes or anticlines (Figs. 14 and 15). These traps were filled by oil moving upward through permeable beds to a point where it was stopped by the impermeable beds on top of the reservoir strata. It is common to find traps partially filled with water where the structure is large enough to hold more oil or gas. Examples of reservoirs formed by anticlinal folding of the structure are the Pegasus field, Midland and Upton Counties, Tex., and the great Azmari Limestone fields of Iran.

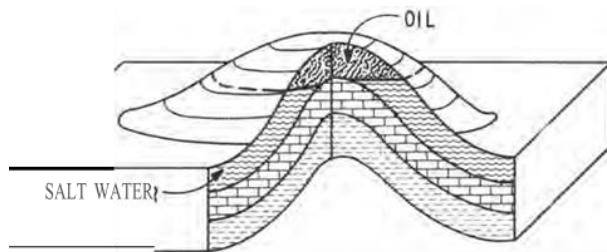


Fig.14. Oil accumulation in a domal structure.

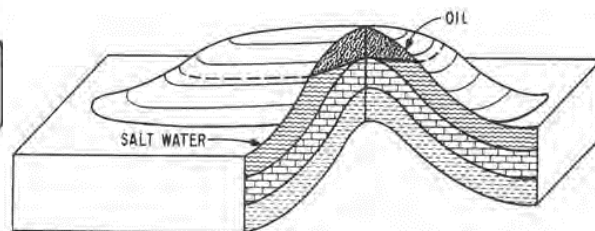


Fig.15. Oil accumulation in an anticlinal structure.

Reservoirs formed by faulting occur where escape of oil is prevented by impermeable beds moving into position against the oil-bearing rock on the opposite side of the fault plane. The oil is held in traps of this type by the structural dip of the bed and the faulting (Fig. 16). Reservoirs of this type are typified by the Mt. Poso field, Kern County, Calif. and the Luling, Mexia and Talco fields in Central Texas.

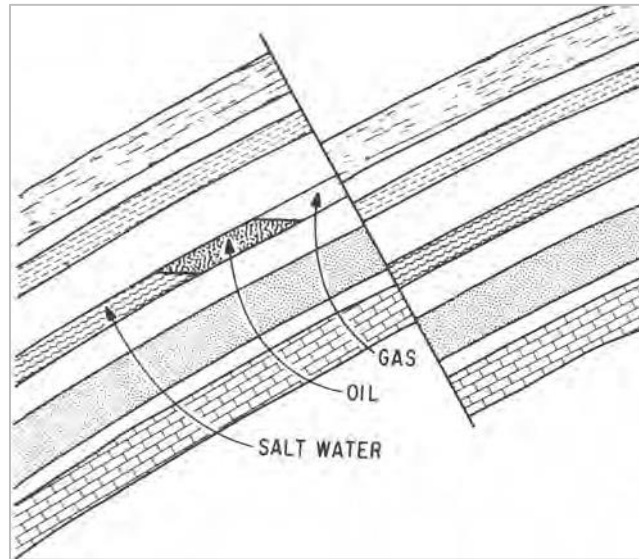


Fig.16. Structural trap resulting from faulting.

Another type of reservoir is one formed as a result of an unconformity where upward escape of oil has been stopped by the impermeable material laid down on the weathered surface of the lower beds (Fig. 17). The East Texas field is formed in this manner.

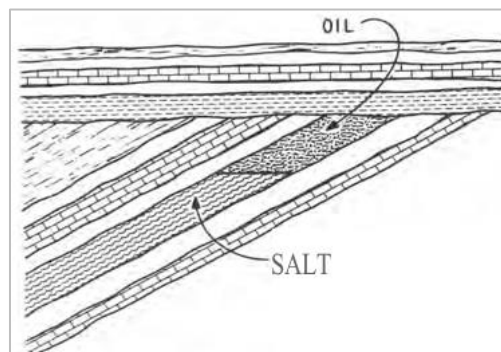


Fig.17. Oil accumulation under an unconformity.

Accumulations of oil are found in sediments on or surrounding material such as salt or serpentine plugs that have pierced and deformed the overlying strata (Figs. 18 and 19). Examples of salt dome fields are the Spindletop field, Jefferson County, Tex. and the Avery Island field, Iberia Parish, La. Examples of serpentine plug fields are the Lytton Springs field in Caldwell County, Tex. and the Hilbig field, Bastrop County, Tex.

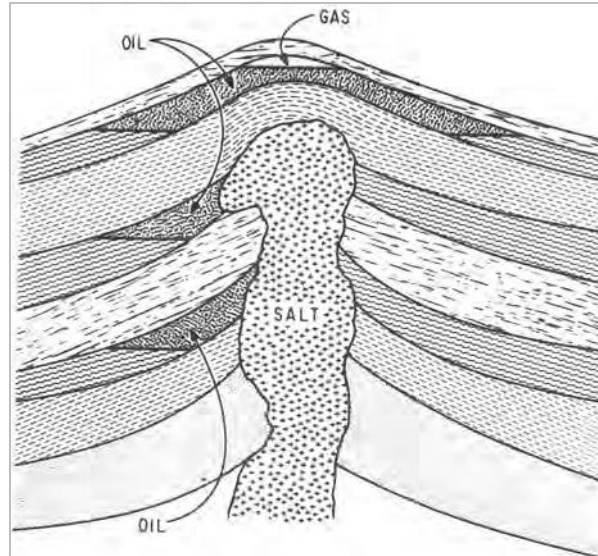


Fig.18. Oil accumulation in the vicinity of a piercement-type salt dome.

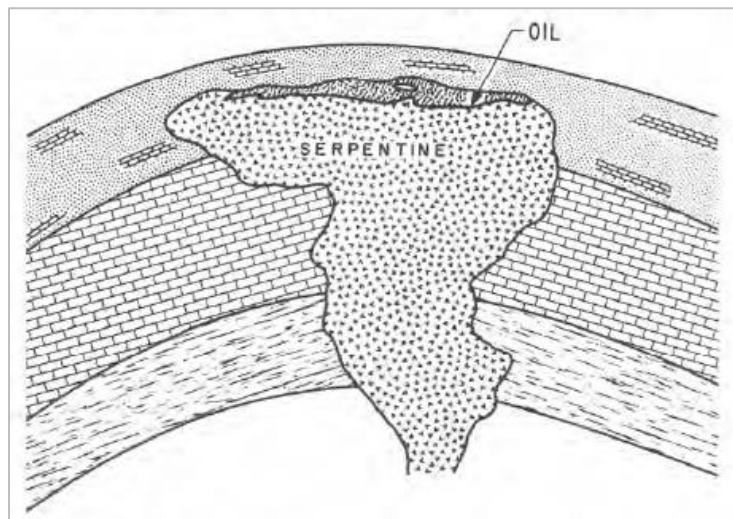


Fig.19. Oil accumulation in areas of porosity in a serpentine plug.

Another type of trap is one that is closed by variation in permeability within the strata (Figs. 20 and 21). The size of oil and gas deposits in reservoirs of this type is governed by the manner in which the beds were laid down rather than by structural closure. In this case, oil is held in place within permeable segments of the bed which are surrounded by impermeable segments of the same bed. Fields having sand reservoirs of this type are the Goose Creek field in Harris County, Tex. and the Sprayberry field in West Texas. Limestone reservoirs of this type are exemplified by the East Dundas field, Richland and Jasper Counties, Ill. (which produce from McClosky limestone) and the Scurry Area Canyon Reef (SACROC) field in Scurry County, Tex. (which produces from a reef section).

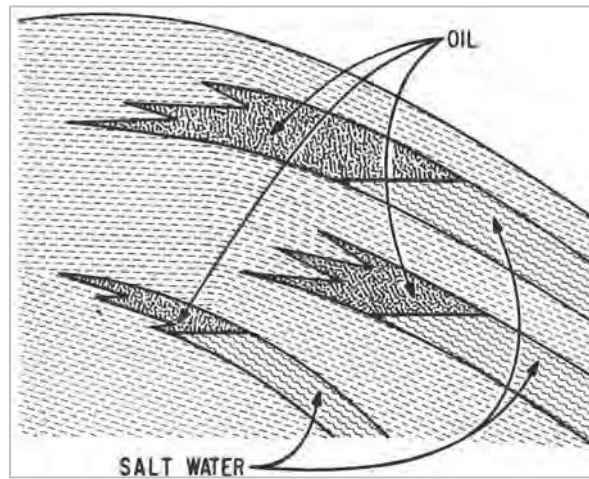


Fig.20. Oil accumulation in sand lenses of the sand bar type.

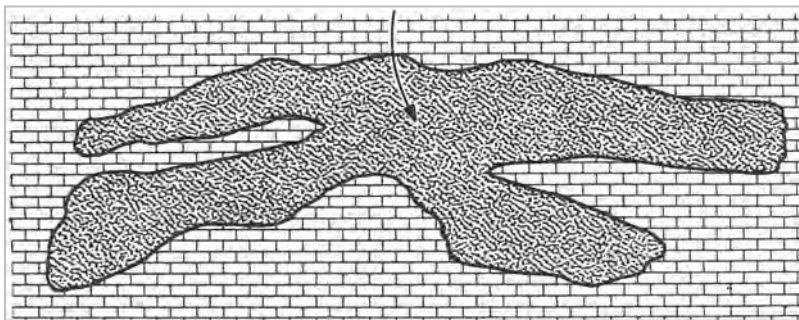


Fig.21. Oil accumulation in porous zones in limestone.

Perhaps the most common type of reservoir is one that is formed not by a single structural feature alone, but instead, by a combination of folding, faulting, changes in permeability or other conditions. Examples of reservoirs of this nature are the many reservoirs found in the Seeligson-Tijerina Canales Blucher- La Gloria trend of fields in Southwest Texas and the Wilmington field, Los Angeles County, Calif.

Chapter 2: Characteristics of Reservoir Rocks

The grains making up sandstones are all irregular in shape. The degree of irregularity, or lack of roundness, evidences as to how the sand grains may have been formed originally or the degree to which they subsequently have eroded. Violent crushing or grinding action between rocks causes grains to be very irregular and sharp-edged. Tumbling action of grains along the bottom of streams or seas smooths sand grains. Wind-blown sand, as occurs in moving dunes of the great deserts, results in sand grains that are even more rounded (Fig. 22). Sand grains that make up sandstone beds and fragments of carbonate materials that make up limestone beds usually never fit together perfectly even though overburden rock pressure on these beds may be quite great. The void space created throughout the beds between grains is called pore space.

The pore spaces in the reservoir rock, sometimes called interstices, provide the containers for the accumulation of oil and gas deposits (Figs. 12 and 13). Pore space, or porosity, in rocks gives the rock its characteristic ability to absorb and hold fluids. Most commercial reservoirs of oil and gas occur in sandstone, limestone, or dolomite rocks; however, some reservoirs occur in fractured shale. Knowledge of the physical characteristics of the pore spaces and of the rock itself (which controls the characteristics of the pore spaces) is of vital importance in understanding the nature of a given reservoir.

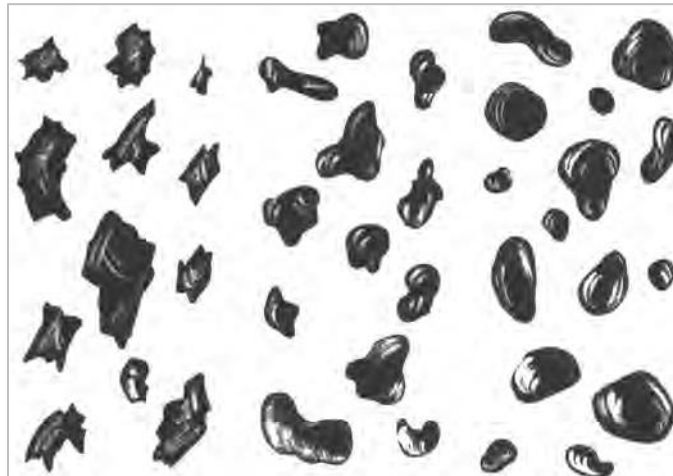


Fig.22. Shapes of sand grains created by various types of erosions.

Porosity

As sand was laid down in geologically ancient seas, the first fluid that filled pore spaces in the sand was sea water or "con-nate" water. Some pore spaces became isolated, but the vast majority in sandstones containing petroleum deposits remained interconnected and have had water in them or moving through them throughout their existence. One method of classifying reservoir rocks, therefore, is based on whether pore spaces in which the oil and gas is found originated when the formation was laid down or whether they were formed through subsequent earth stresses or ground water action. The first type of porosity is termed "original porosity" and the latter,

"secondary porosity". Most sandstone porosity is original while most limestones and dolomites owe their porosity to secondary formation.

Secondary porosity in limestone beds occurred as a result of fracturing, jointing, solution, recrystallization or a combination of these. Original porosity in limestone is important because such must have been present when artesian water entered and began its solution work on the limestone rock formation.

Where water is present in a carbonate formation, there is a continuous process of solution and deposition or recrystallization. If solution is greater than deposition in any zone, porosity will be developed between the crystal grains. An important type of porosity of this kind is found in dolomite zones which occur in conjunction with large limestone deposits. Dolomite may be deposited originally as a sedimentary rock, or it may be formed by replacing the calcium carbonate in limestone rock with magnesium carbonate.

Porosity is measured as a per cent of total rock volume. The most useful way to classify porosity (Fig. 23) is into categories of effective porosity (continuous or interconnected porosity), non-effective porosity (discontinuous or isolated porosity), and total porosity (the sum of all the porosity). Only effective porosity has real significance in rocks containing present-day commercial oil and gas deposits because it is only from this type of porosity that the fluids can move and be recovered.

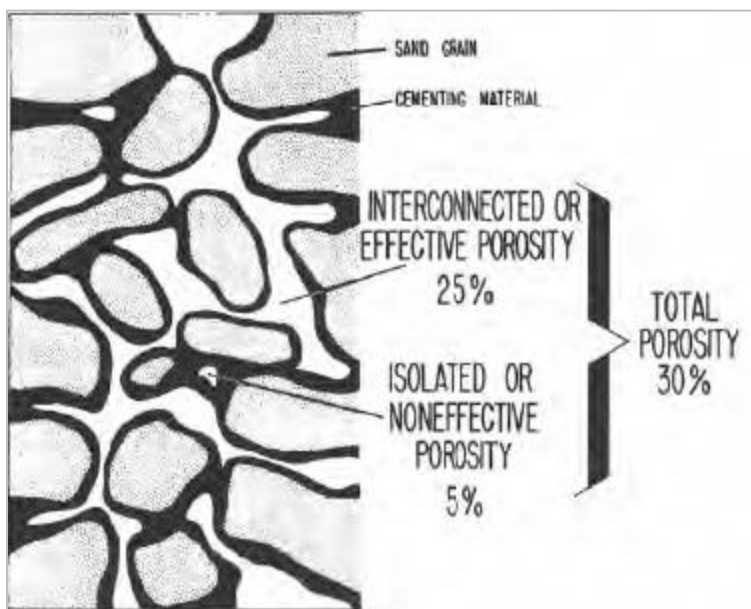


Fig. 23. Effective, non-effective and total porosity.

Permeability

The ease with which a fluid can move through the interconnected pore spaces of the rock denotes the degree of permeability possessed by the rock. The rock is more or less permeable depending upon whether the rock will let fluid pass through it with greater or less ease. This is similar

to pipelines where larger or straighter fines let fluid move through more easily. Many rocks are impervious to movement of water, oil or gas even though they may actually be quite porous. Some of these are clays, shales, chalk, anhydrite, and some highly cemented sandstones.

When considering the permeability of rock, we must immediately think in terms of the force which makes fluid flow through the rock. Such force is pressure, just as in a pipe where a pressure is applied to force liquid or gas to move through the pipe. In 1856, the French engineer Henry Darcy performed tests on water filters, and some of this work provided the engineering profession with the relation which permits measurement and study of the ease of fluid flow through porous rock. Darcy's law of fluid flow states that rate of flow through a given rock varies directly according to some numerical quantity and the pressure applied and varies inversely according to the viscosity of the fluid flowing.

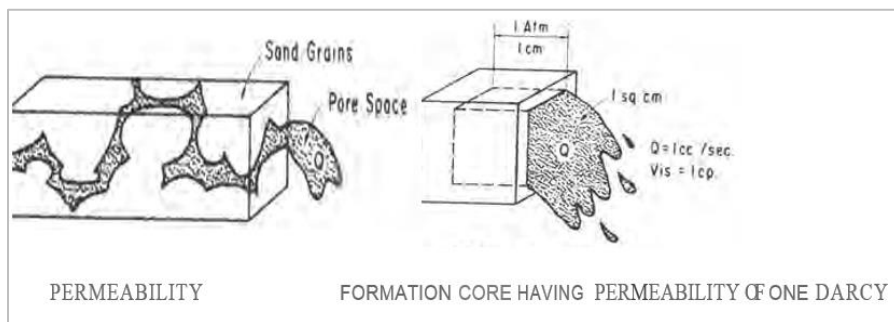


Fig.24. Fluid flow in permeable sand.

The numerical quantity is the permeability and is measured in darcies. A sandstone having 1 Darcy of permeability is defined as a 1 cubic centimeter of fluid of 1 centipoise viscosity (or the viscosity of water at 68°F) would flow each second through a portion of the sand 1 centimeter in length and having 1 square centimeter of area through which it moves if the pressure drop across the sand is 14.7 pounds per square inch (or equivalent to atmospheric pressure), as shown in Fig. 24.

Reservoir rock having an average permeability as great as 1 Darcy is found in only a small portion of the reservoirs containing petroleum deposits. The usual measure of rock permeability, therefore, is in millidarcies (md) or thousandths of a Darcy.

The magnitude of permeability, in terms of oil production from a reservoir rock into a well, is illustrated by the fact that a reservoir rock 10-feet thick, having 1 Darcy of effective permeability will permit about 150 barrels of oil per day to flow into a wellbore if the pressure in the well is 10 pounds per square inch below the pressure out in the reservoir.

Factors that Influence Porosity and Permeability

Porosity and permeability of sandstone depend upon many factors, among which are size and shape of the grains, variations in size of grains, arrangement in which grains were laid down and compacted, and amount of clay and other materials which cement the sand grains together.

Size of the sand grains which make up a rock do not influence the amount of porosity occurring in the rock. However, variations in sand-grain sizes do influence considerably the percent of porosity.

An example is shown in Fig. 25, where porosity between spheres of 1-inch diameter is the same as porosity between spheres of $\frac{1}{2}$ -inch diameter, provided the spheres are arranged in the same manner. If they are arranged in cubic order, porosity is about 48 percent; whereas if they are arranged in rhombohedral order, porosity is about 26 percent. If spheres of varying sizes are packed together, porosity may be any amount from 48 percent to a very small amount approaching 0 percent as shown in Fig. 26. This principle is illustrated in mixing concrete, where the basic materials are gravel mixed with sand, with the resulting mixture having very little porosity and requiring only a small amount of cement and water to fill the remaining pore space completely.

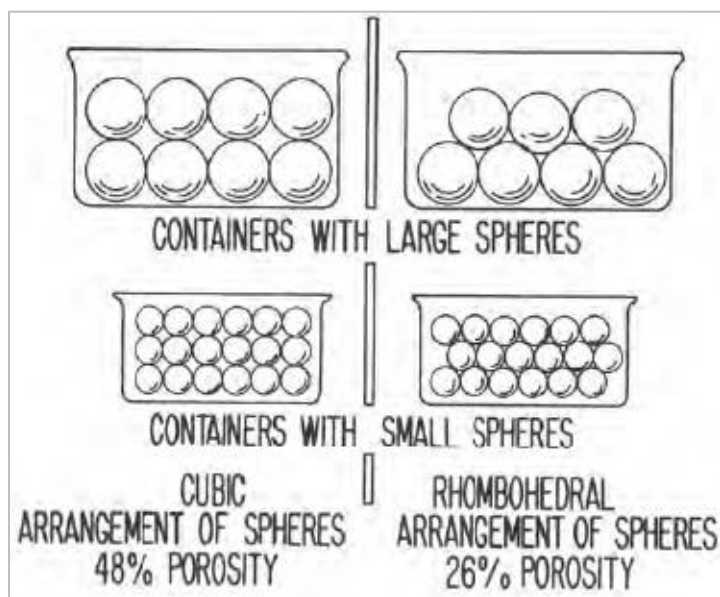


Fig. 25. Effects of size and arrangement of spheres on porosity.

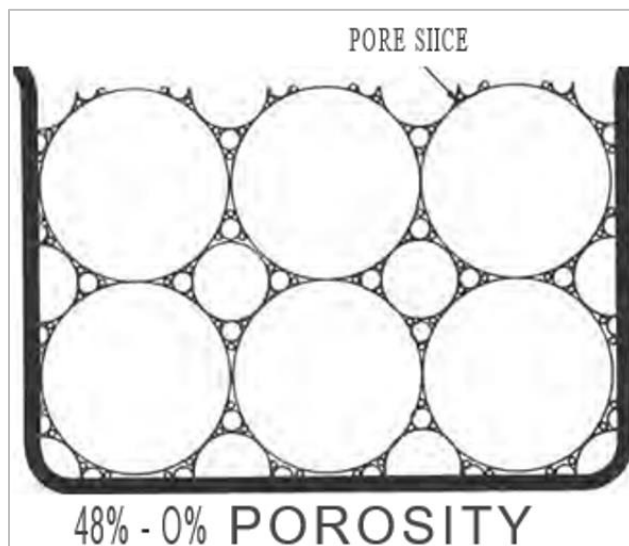


Fig. 26. Effect of variations in size of spheres on porosity.

To illustrate variation in porosity and permeability with a given type of sand grain, various features are considered separately. If the sand grains are elongated or flat and are packed with their flat surfaces together, porosity and permeability may both be low. Permeability along the flat surfaces

will be higher, however, than the permeability in a direction that is perpendicular to, or across, the flat surfaces of the grains. In a reservoir, the permeability horizontal with the bed is usually higher than the permeability vertical across the bed because the process of sedimentation, where the sand grains are washed to their final position, causes the grains to be laid down with their flattest sides in a horizontal position.

If sand grains of generally flat proportions are laid down with the flat sides non-uniformly positioned and located in indiscriminate directions, both porosity and permeability may be very high (Fig. 27). To illustrate, if bricks are stacked properly, pore space between the bricks is very small; yet if the same bricks are piled indiscriminately, space between the bricks might be quite large.

The shape and size of sand grains are important features that determine the size of the openings between the sand grains. If the grains are elongated, large and uniformly arranged with the longest dimension horizontal, permeability to fluid flow through the pore channels will be quite large horizontally and medium-to-large vertically. If the grains are more uniformly rounded, permeability will be quite large in both directions and more nearly the same. Permeability is generally found to be lower with smaller grain size if other factors are not influential. This occurs because the pore channels become smaller as the size of the grains is reduced, and it is more difficult for fluid to flow through the smaller channels (Fig. 28).

Sandstones are compacted and cemented together with clays and minerals. Porosity and permeability of a sandstone is both influenced to a marked degree by the amount of cementing material present in the pore channels and the way this material occupies the pore space between the sand grains (Fig. 29). This is true because the cementing material may be uniformly located along the pore channels to somewhat reduce both porosity and permeability; or, the cementing material may be located so as to congest only the pore openings, where a small amount can reduce permeability drastically while leaving the porosity quite high.

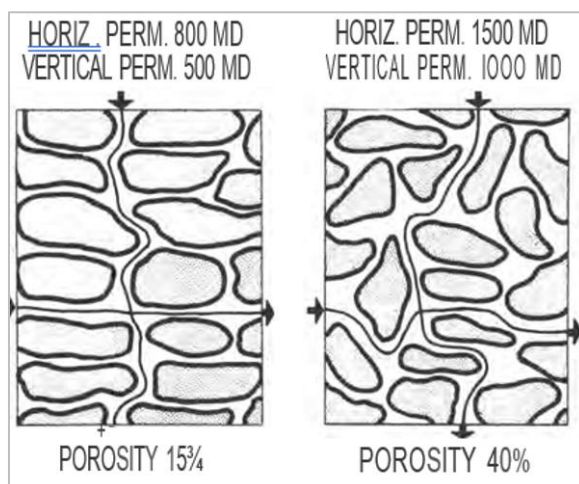


Fig. 27. Variations in porosity and permeability with sand grain arrangement.

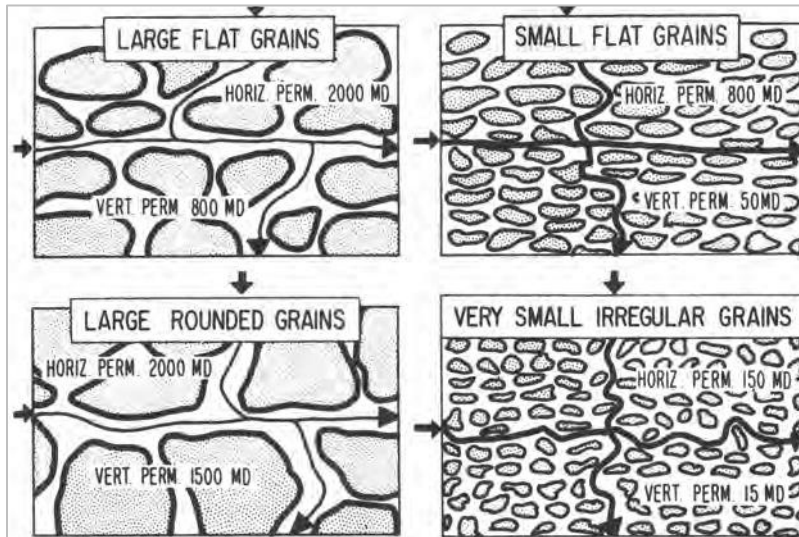


Fig.28. Effects of shape and size of sand grain on permeability.

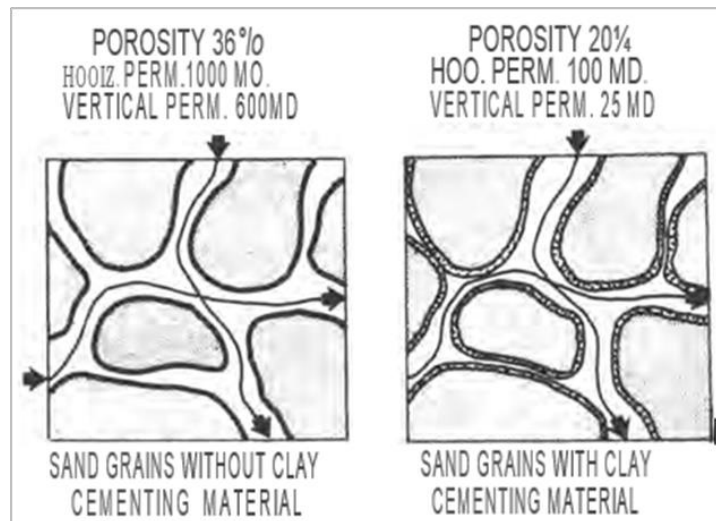


Fig.29. Effects of clay cementing material on porosity and permeability.

Limestones, except for the granular oolitic type, which may be similar in character to sandstone, are composed of more densely spaced particles and depend for porosity upon the space between microscopic crystals in the rock, solution void spaces caused by movement and solvent action of ground waters, and other spaces formed by fractures and joints caused by earth stresses. Porosity and permeability, however, have the same meaning in limestone as in sandstone, although they are usually extremely irregular and much more difficult to measure and analyze.

Thin sections and impregnated sections of samples of three sandstones from the Waltersburg, Weber and Woodbine formations are shown in Fig. 30.

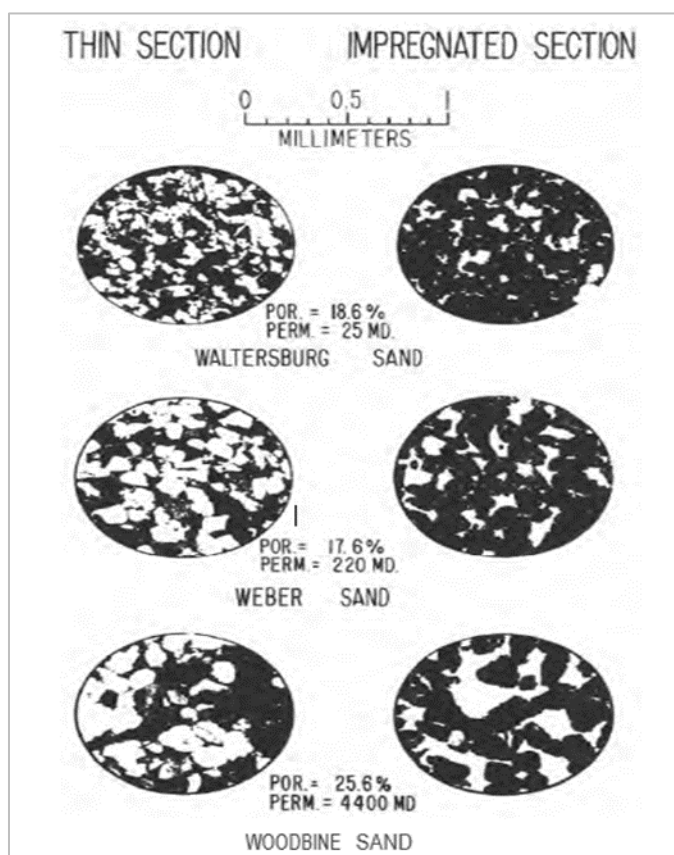


Fig. 30. Grain structure shown by thin section, and porosity shown by impregnated section of three sandstones. (Courtesy BULLETIN OF AAPG-Feb., 1952)

The thin sections show size and distribution of the grains, and the other sections are impregnated with Woods metal, then polished to show size and distribution of the pore spaces. The Waltersburg sand has smaller grains and pore channels than the Weber, but there are more pore channels volume-wise. Thus, porosity is greater in the Waltersburg than the Weber. On the other hand, pore channels in the Weber are larger than those in the Waltersburg; therefore, permeability in the Weber is much greater. Woodbine grains and pore channels are much larger than the other sands shown. The porosity of the Woodbine is greater because of the presence of less packing and less cementing material. Permeability is very high because the pore channels are large and less cementing material is present to impede fluid flow.

In summary, the amount of porosity is principally determined by shape and arrangement of sand grains and the amount of cementing material present, whereas permeability depends largely on size of the pore openings and the degree and type of cementation between sand grains. Although many formations show a correlation between porosity and permeability, the several factors influencing these characteristics may differ widely in effect, producing rock having no correlation between porosity and permeability.

Relative Permeability

Permeability is the measure of the ease with which a fluid flows through connecting pore spaces of a reservoir rock. Because not one, but three fluids; gas, oil and water can flow in petroleum reservoirs, another type of permeability must be considered. When dealing with the flow of more than one fluid through a sand, one must consider relative permeability relationships—the ease with which one fluid, of the two or more fluids present, will flow through connecting pore spaces in the presence of each other as compared to the ease with which one fluid will flow when it is present alone.

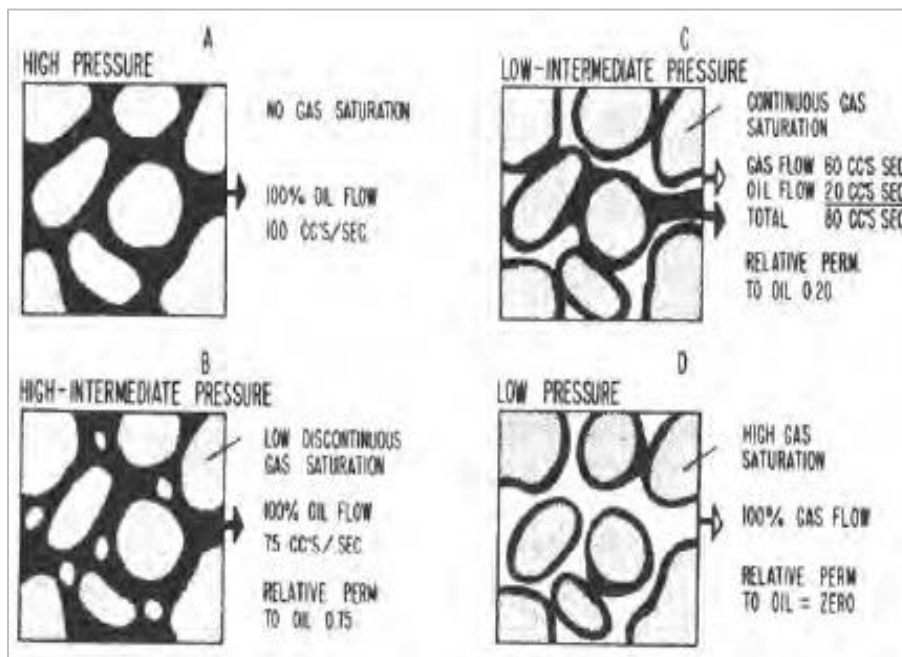


Fig. 31. Concept of relative permeability showing that a change in the amount of a fluid present in the pore channels will change the rate at which that fluid flows, relative to the rate it would flow if only that fluid was present.

Consider an oil reservoir at high pressure (Fig. 31A). Gas has not been allowed to come out of the solution (Chapter 3); therefore, all available space is filled with oil, and only oil is flowing. If the reservoir pressure is allowed to decline, some lighter components of the oil will evolve and collect as gas in the pore space crevices between sand grains (Fig. 31B).

If the pressure decline is slight, then the gas that forms will not be sufficient to form a continuous pore-to-pore gas saturation; still only oil can flow from the pore spaces. Gas, though it does not flow, slows down the flow of oil by its presence. If reservoir pressure is further reduced, the small bubbles of gas in each pore will grow in size until a continuous gas phase is established along the pore network (Fig. 31C). Production will then be oil and gas. The percent of gas saturation in the pore space at the time when gas starts to flow is termed “equilibrium gas saturation” and differs somewhat in different sands because of variations in sand pore space configuration.

As pressure continues to decline, or as the gas saturation continues to increase, more and more gas and less and less oil flow in the sand until finally almost 100 percent gas is flowing (Fig. 31D).

Relative permeability, then, can be defined as the rate of flow of one fluid (such as oil) through pore channels in the presence of a second fluid (such as gas) as compared to the rate of flow if, under the same pressure drop conditions, only the one fluid was present.

For example, if the amount of oil flowing in Fig. 31B is only 75 percent as much as that flowing in Fig. 31A, relative permeability of the sand to oil, with the sand saturated with the percentages of oil and gas shown in Fig. 31B, is 0.75. The flow of oil in Fig. 31C may be reduced to 20 percent; thus, at the conditions of saturation shown, the sand would have a relative permeability to oil of 0.20. Relative permeability to oil is zero where oil saturation has been decreased to a minimum (Fig. 31D).

This same principal governs the flow of gas in the presence of either water or oil. The amount of each fluid present, making up the saturation condition of the pore spaces, will control the ease of fluid movement and thus the relative permeability relationship of the reservoir rock. This relationship is a function of the configuration of the rock pore spaces and the wetting characteristics of the fluids and rock surfaces.

Chapter 3: Characteristics of Oil and Gas

Nearly all naturally occurring petroleum deposits are made up of an extremely large number of petroleum compounds, all mixed together. Molecules of all these compounds are composed of the chemical elements hydrogen and carbon in various proportions. Petroleum compounds of these elements are called hydrocarbons, and each compound is made up of a different proportion of the two elements. Seldom are two crude oils found that are seemingly identical and certainly never are two crude oils made up of the same proportions of the various compounds. Within a single petroleum deposit, the mixture differs some from place to place and in many cases to an extreme degree.

Components of Petroleum

The vast number of hydrocarbon compounds making up petroleum have been grouped chemically into series of compounds. Each series consists of those compounds similar in their molecular make-up and characteristics. Within a given series, there exist compounds from extremely light, or chemically simple, to heavy, or chemically complex. As an analogy, the hydrocarbons may be compared to cattle; just as cattle are classified into different breeds, hydrocarbons are classified into different series. Just as there are a multitude of different cattle sizes within a breed, within a hydrocarbon series, there are a multitude of compounds that differ due to the weight of the molecules of which they are made.

The most common and greatest number of hydrocarbon compounds making up a naturally occurring petroleum deposit are those of the paraffin series, which includes methane, ethane, propane, butane and others (Figs. 32 and 33). Because of this, it has been the practice in the petroleum producing industry to analyze all petroleum samples according to their fractional composition based on the boiling properties of the various paraffin series constituents.

The composition of most petroleum deposits will include some quantity of nearly all components throughout the entire range of weights and complexities, whether the hydrocarbon is heavy crude oil with characteristics approaching tar, or the lightest of natural gases from which liquids can be condensed only with great difficulty. Gas, therefore, is not a gas because it is composed entirely of light molecules which are different from those making up crude oil. Naturally occurring gas is different because the majority of its component molecules are lighter and simpler, whereas liquid crude oil is made up of a majority of the heavier and more complex component molecules. Both natural gas and crude oil, however, contain some of most all existing hydrocarbon components.

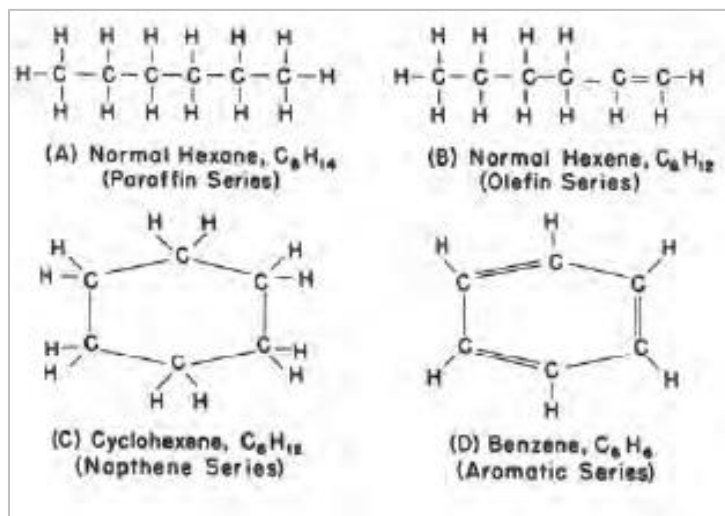


Fig.32. Structural formulas of four hydrocarbon series (compounds containing six carbon atoms).

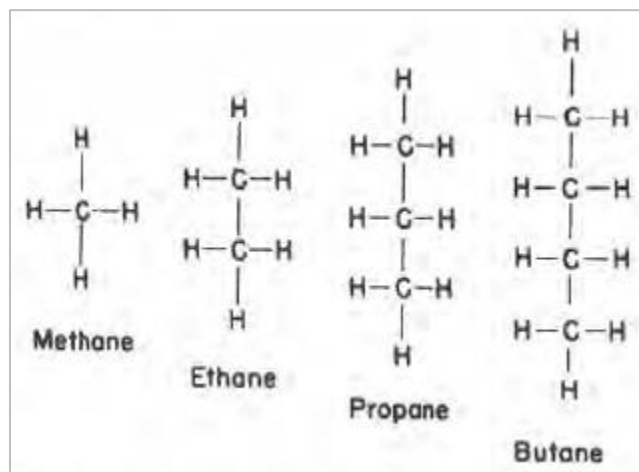


Fig.33. Structural formulas of the four lightest paraffin compounds.

Phases of Petroleum

Because of a man's environment of earth, water and air, it could well have been that his first scientific observations were that matter existed in three states or forms; solid, liquid and gas. Generally, it is found that all substances may exist in any of the three forms which have been termed phases of matter.

Whether a substance exists in a solid, liquid or gas phase will be determined by temperature and pressure conditions acting on the substance. It is well known that steam can be changed to water by lowering its temperature and water can be changed into ice by further lowering its temperature. Hydrocarbon compounds, either individually or in mixtures, will change their state or phase in the same way by changing their temperature and pressure. The resulting change is called "phase behavior".

Heavy hydrocarbons, including paraffin and tars, sometimes form naturally as solids in the reservoir and present problems in oil production operations; however, this does not often happen, and such problems will not be discussed herein. The scope of this book will be limited to the behavior of hydrocarbons as they change from gas to liquid and liquid to gas and the operating problems and their control caused by such changes.

Molecular Behavior

Hydrocarbons behave peculiarly when their pressure and temperature are changed. This behavior is best explained by the behavior of the individual molecules making up the mixture. Four physical factors are important in governing the behavior of hydrocarbon matter. These are (1) pressure, (2) molecular attraction, (3) kinetic energy (molecular motion associated with temperature) and (4) molecular repulsion (Fig. 34).

Pressure and molecular attraction tend to confine molecules or pull them together so that the greater the value of these forces, the greater the tendency for the material to become more dense, as is the case when gases become liquid.

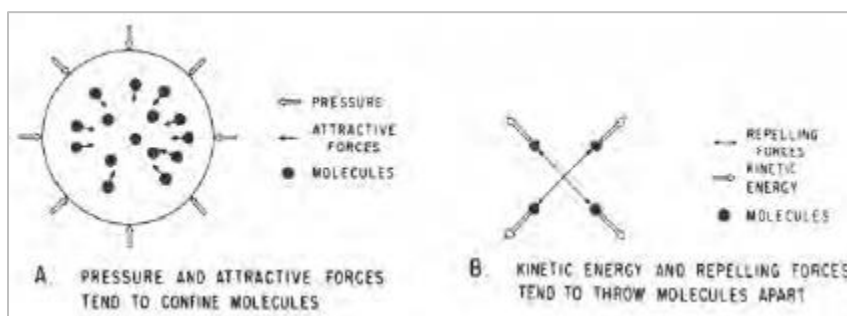


Fig.34. Forces governing hydrocarbon behavior.

Molecular attraction is considered an internal pressure since it is within the system and acts on the molecules in the same way as external pressure. Attractive force between molecules changes with distances between the molecules, the force increases as the distance between the molecules decreases; it differs with the mass of molecules, the force increases as the mass of the molecules increases.

Kinetic energy, or molecular motion, increases as temperature increases so that the greater the temperature of a material, the greater the tendency for the material to be thrown apart, and thus decreases in density or changes from a liquid to a gas (or for a gas to expand).

When molecules get so close together that their electronic fields overlap, a repelling force is present that tends to increase the resistance of the material to further compression. When hydrocarbon material appears to be at rest (not expanding, contracting in volume or changing state), the forces tending to confine the molecules balance the forces tending to throw them apart, and the material is considered to be in equilibrium.

Changes in Phases

If pressure is increased, molecules are forced closer together so that gas will be compressed or changed to a liquid. However, as pressure is decreased, the reverse occurs; gas expands and liquid tends to vaporize to gas. The molecules in the latter case are thrown apart by their own kinetic energy and molecular repulsion. These phase changes caused by changes in pressure are termed normal or regular behavior.

If the molecules are smaller, as in the case of methane and ethane, there is less attraction between molecules and greater tendency for them to be thrown apart by their kinetic energy into gas; whereas, if molecules are larger, as in hexane and heptane, they tend to be attracted together into the liquid rather than thrown into the gaseous state by their kinetic energies. As the temperature of the compounds increases, kinetic energy increases. The tendency then is for all molecules in the liquid state to be thrown into the gaseous state and for gases to expand. However, if temperature is decreased, the kinetic energy decreases, and all molecules (even the lighter molecules) tend to be attracted together into a liquid state and even frozen into the solid state if the temperature is low enough. This behavior is also considered normal or regular.

Pure Hydrocarbons

For a single or pure hydrocarbon such as propane, butane or pentane, there is a given pressure for every temperature at which the hydrocarbon can exist both as a liquid and a gas. This is demonstrated in Fig. 35. Under these conditions, the forces which tend to pull the molecules closer together (pressure and attractive forces) balance the kinetic energy which tends to throw them apart. If pressure is increased without a temperature change, the gas molecules are forced closer together and the attractive forces between molecules are thus increased. The forces then tending to pull molecules together are greater than the kinetic energy, and the molecules condense to a liquid state.

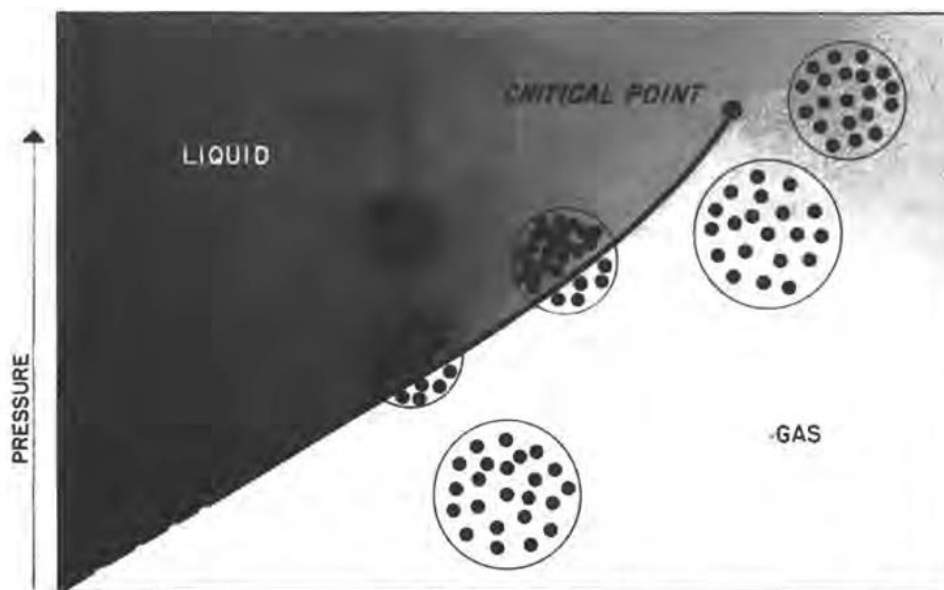


Fig.35. Vapor pressure vs temperature for a pure hydrocarbon component. (Courtesy World Oil- March, 1953)

However, if pressure is decreased without a temperature change, the distance between gas molecules is increased, and the attractive forces are thus decreased. Forces tending to pull the molecules together are then less than the kinetic energy, and the molecules disperse into a gas.

Actually, pressure results from the molecular bombardment of the containing vessel and liquid surface. The increase in volume tends to reduce the pressure by increasing the distance molecules must move to strike the container. As temperature increases, kinetic energy is increased; higher pressures are required for existence of the balanced conditions at which the two phases can exist simultaneously. The curve (Fig. 35) plotted through the pressure-temperature points where two phases exist is called the "vapor-pressure curve". There is a temperature above which the material will not exist in two phases regardless of the pressure. This is called the "critical point", and temperature and pressure at this point are called "critical temperature" and "critical pressure".

It is common practice to consider the material as a gas when it exists at temperature and pressure conditions below the vapor-pressure curve, and as a liquid above the vapor-pressure curve. Such a definition obviously is confusing because ranges of temperature and pressure exist in which the material can be classified as either liquid or gas. These ranges are shown in the upper right-hand portion of Fig. 35. In these ranges, the temperature is so great that attractive forces between the molecules are not sufficiently great to permit them to coalesce to a liquid phase because of the higher kinetic energy of molecules at the high temperature condition. Under these temperature conditions, an increase in pressure causes the molecules to move together uniformly as pressure is increased. This confusion is minimized when working with reservoirs because reservoir temperature (and thus the temperature of the hydrocarbons in the reservoir) usually remains constant; therefore, only pressure and volume are usually altered to an appreciable degree in the reservoir during production.

Hydrocarbon Mixtures

In a mixture of two components, the system is no longer so simple in its behavior as the one component, or pure, substance. Instead of a single line representing the pressure-temperature relationship, there is a broad region in which two phases (liquid and gas) coexist. Fig. 36 is a diagrammatic correlation, or phase diagram, of the phase behavior of a 50:50 mixture of two hydrocarbons such as propane and heptane. Superimposed on the correlation are vapor-pressure curves of the two components in their pure state.

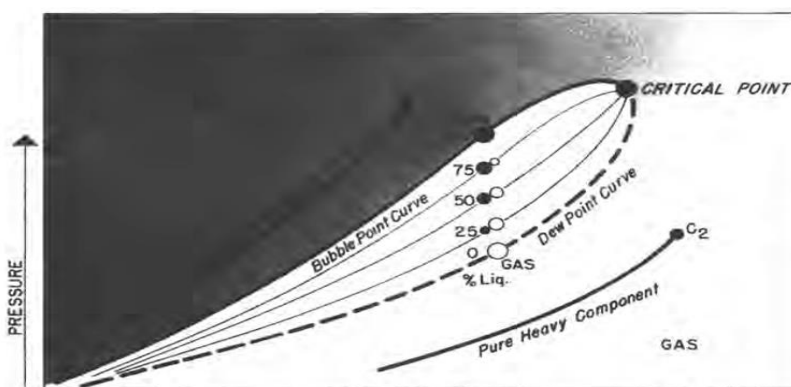


Fig. 36. Vapor pressure curves for two pure components and phase diagram for a 50:50 mixture of the same components. (Courtesy World Oil- March, 1953)

The two-phase region of the phase diagram is bounded on one side by a bubble-point line and on the other by a dew-point line, with the two lines joining at the critical point. A bubble point occurs where gas begins to leave solution in oil with decreasing pressure, while a dew point is reached when liquid begins to condense from gas with either decreasing or increasing pressure. Of importance is the fact that, for a given temperature, the pressure at which a mixture of two components is condensed to total liquid is lower than the pressure at which the lighter component in the mixture would condense if it were not in the mixture.

The pressure at which the mixture of two components is vaporized to total gas is higher than the pressure at which the heavy component would vaporize if it were not in the mixture. This is caused by the attractive forces between molecules of like and unlike sizes. Attraction of the heavy for light molecules pulls the light material into the liquid at a lower imposed pressure than would the light molecules among themselves in the absence of the heavy molecules. Attraction of the light for heavy molecules pulls the heavy material into a gas at a higher imposed pressure than would the heavy molecules among themselves in the absence of light molecules.

At the critical point, properties of both gas and liquid mixtures are identical. It is significant that the definition of critical point, as applied to a single-component system, no longer applies because both liquid and gas phases exist at temperatures and pressures above the critical point, although the degree may be slight in a system of only two components. As the system becomes more complex with a greater number of different components, the pressure and temperature ranges in which two phases exist increase greatly.

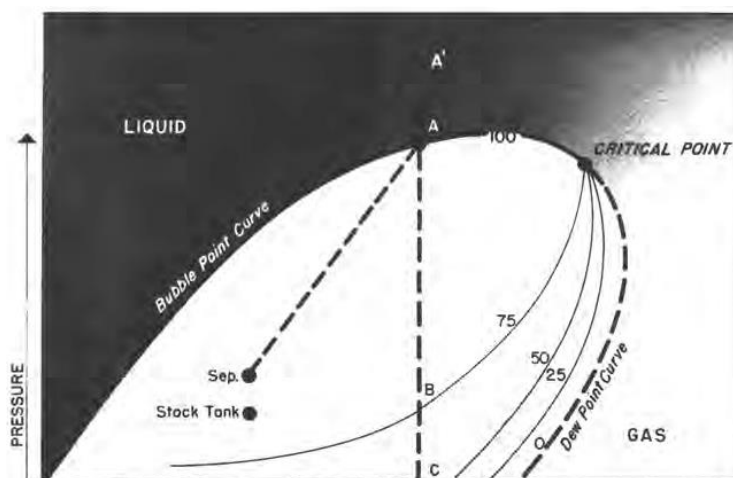


Fig. 37. Phase diagram of low shrinkage oil.

An idealized pressure-temperature phase diagram of a common, naturally occurring petroleum is shown in Fig. 37. If the oil existed at its bubble point, or if the original reservoir pressure was the saturation pressure of the mixture, the petroleum would be existing at A. If the pressure of this same oil should be at A, the oil would be undersaturated. Separator and stock tank temperatures and pressures are indicated. Quantities of liquid and gas represented by location of the stock tank point on the diagram, however, do not indicate what would occur in the stock tank because the original mixture changes at the separator in the oil and gas production process.

Vertical or constant temperature line A-B, represents the path the material takes into the two-phase

region as pressure is dropped at reservoir temperature and represents quantities of liquid and gas existing in equilibrium at temperature and pressure conditions represented by the given location of the point in the phase loop. This is physically represented in the reservoir by gas coming out of solution, the amount of which is governed by the amount of drop in pressure.

Equilibrium Separation

Low Shrinkage Oils

A given volume of oil existing at its bubble point at reservoir temperature is considered to be saturated with gas at the given temperature and pressure conditions. Thus, the term "saturation pressure" is synonymous with bubble-point pressure at a given temperature. A decrease in pressure will cause the original sample to change into two phases as shown in Fig. 38. The physical change is evidenced as gas being liberated from the liquid.

It is a common misbelief that a certain amount of gas is dissolved in oil and that a pressure drop results in the gas coming out of solution. Actually, the first gas liberated is composed principally of the lightest components (methane, ethane and propane) because these components possess the highest molecular energy and the lowest molecular attraction for other molecules.

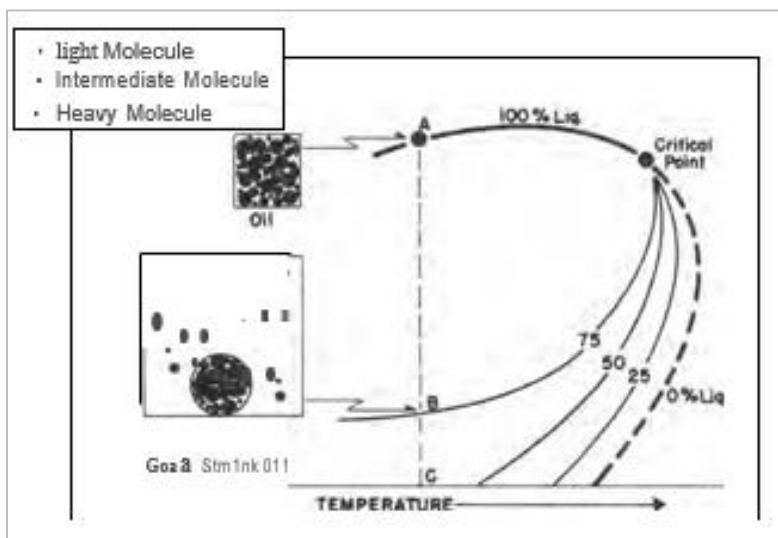


Fig.38. Equilibrium vaporization of low shrinkage oil.

Vaporization of the lighter components is usually followed by quantities of heavier components until some low pressure is reached where only a fraction of the original materials remains liquid. Portions of all the component materials (including heavy components) have gone into the gas phase with, of course, a greater percentage of the lightest materials composing the gas. The gas formed has done so by vaporization of the light components and, as a result, the remaining liquid is described as having shrunk in volume. This change is illustrated in Fig. 38 for a typical low shrinkage oil, or one that shrinks only a small amount.

For low shrinkage oil, there is a somewhat uniform change in shrinkage as pressure drops through the high and intermediate pressure range (A to B, Fig. 37 and A to B on the low shrinkage oil curve in Fig. 39). This shrinkage occurs principally as a result of volumetric loss of light materials. It increases rapidly, however, through the low-pressure range (B to C, Figs. 37 and 39). This shrinkage occurs principally through volumetric loss of intermediate and heavy material from the remaining liquid. Shrinkage characteristics of this range of pressures are extremely significant because surface separation of oil from gas occurs under these conditions.

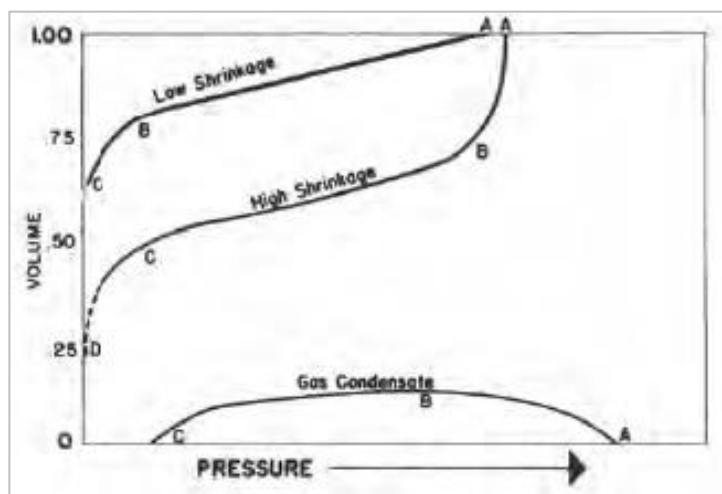


Fig.39. Equilibrium shrinkage of hydrocarbon liquids.

Increasing shrinkage at low pressure is caused by kinetic energy of the heavy liquid molecules being greater than attractive forces within the liquid under these reduced pressure conditions.

High Shrinkage Oils

Certain oils are known as high shrinkage oils because their shrinkage with pressure reduction is greater than normal. The term "high shrinkage" is qualitative because there is no distinct set of conditions by which low and high shrinkage oils may be classified. Higher shrinkage is usually brought about because of the existence of greater quantities of intermediate components or lesser quantities of heavy components in the mixture.

Changes in oil shrinkage by vaporization of material through pressure reduction is illustrated by temperature condition Tr_2 in the phase diagram in Fig. 40 and the high shrinkage curve in Fig. 39.

Behavior of high shrinkage oil in the high pressure range is different from that of low shrinkage oil. As pressure drops slightly from saturation pressure (A to B), not only do the light component molecules leave solution, but a large quantity of intermediates also leave solution to form gas. Actually, it is the presence of this large quantity of intermediate components that makes a high shrinkage oil. High shrinkage of the oil from A to B is caused not only by attraction of intermediate component liquid molecules to closely spaced, light component gas molecules, but also by the normally high kinetic energy of the intermediate component liquid molecules.

As pressure drops further (B to C), the attraction for intermediate component liquid molecules by light component gas molecules decreases because of an increase in the distance separating them;

therefore, there is a tendency toward greater attraction between the remaining liquid intermediates to liquid heavies, which prevents further rapid vaporization throughout the middle pressure range. Vaporizing tendency of heavy component liquid molecules increases through the low-pressure range (C to D), just as in the case of low shrinkage oils, although to a greater degree because of the greater quantity of intermediates held by attraction to the heavy liquid molecules until the low-pressure condition is reached. High shrinkage oils behave similarly to low shrinkage oils in the low pressure range, except that shrinkage is much greater. Shrinkage characteristics of high shrinkage oils are, therefore, of great significance in surface separation problems.

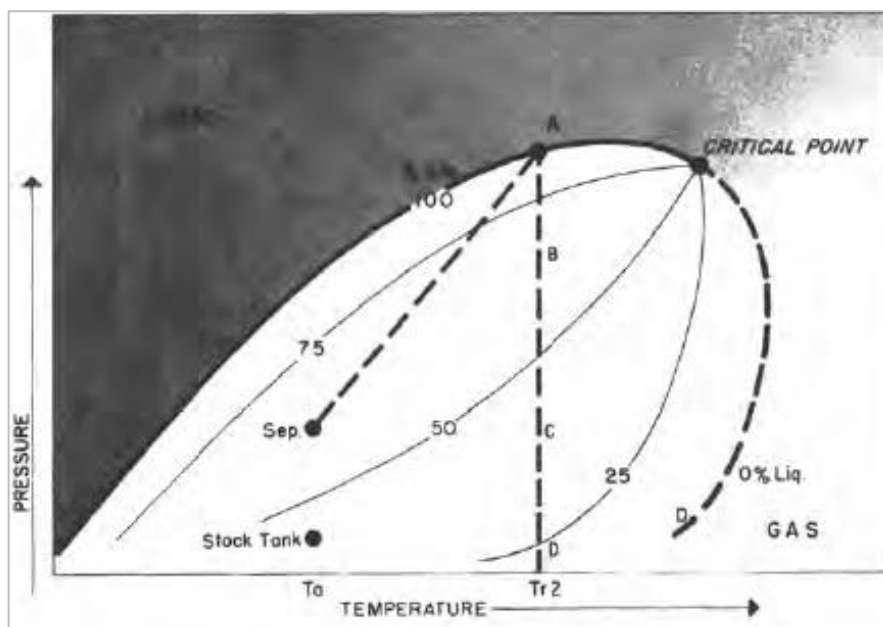


Fig.40. Phase Diagram of high shrinkage oil.

Retrograde Condensate Gas

Some hydrocarbon mixtures exist naturally above their critical temperature as gas condensates. When pressure is decreased on these mixtures, instead of expanding (if a gas) or vaporizing (if a liquid) as might be expected, they tend to condense. Conversely, when pressure is increased, they vaporize instead of condensing. The process is illustrated by temperature condition Tr_3 in Fig. 41, and the gas condensate curve in Fig. 39. This process is caused by forces acting on molecules of unlike sizes and depends upon a balance of these forces, as illustrated in Fig. 42.

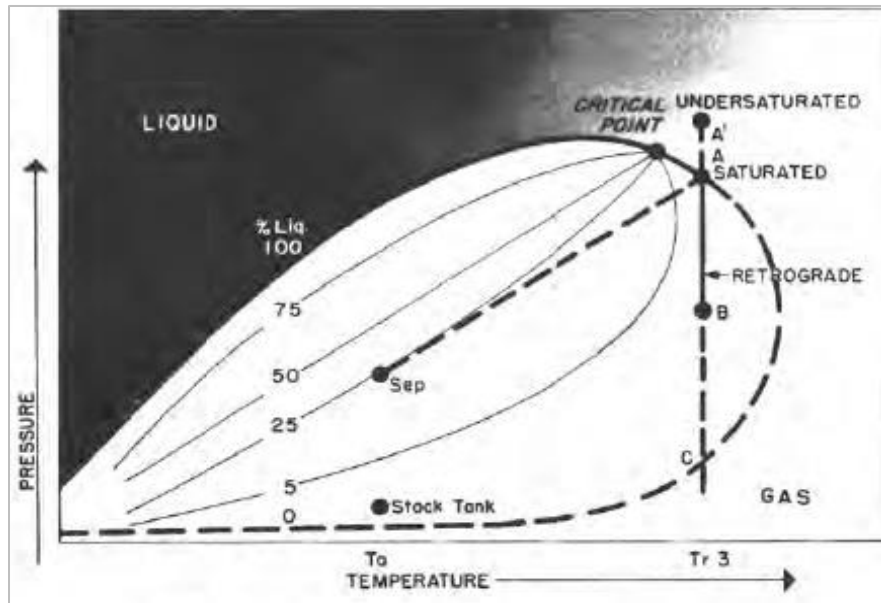


Fig. 41. Phase diagram of retrograde condensate gas. (Courtesy World Oil- March, 1953)

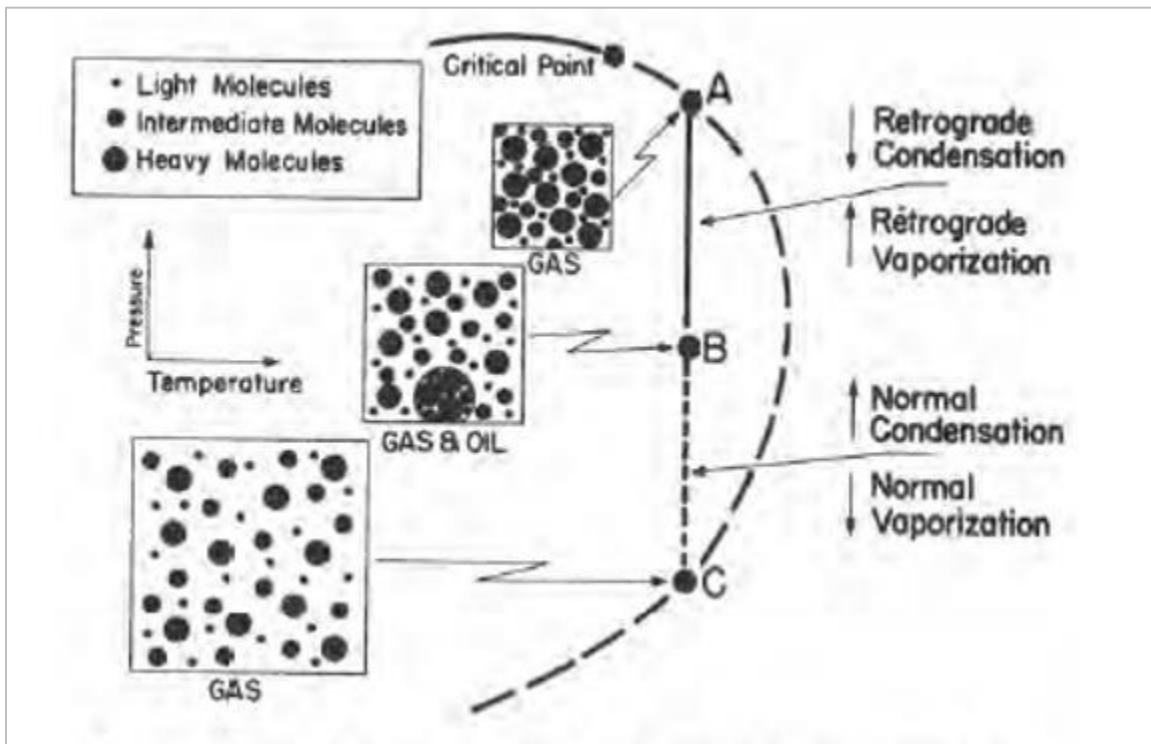


Fig. 42. Equilibrium retrograde behavior of condensate gas. (Courtesy World Oil- March, 1953)

Normal vaporization and condensation, on the other hand, depend more upon balance between molecular forces of like-size component molecules.

As pressure drops (at constant temperature) below dew-point pressure (A), the attraction between light and heavy component molecules decreases because the light molecules move farther apart.

As this occurs, attraction between the heavy component molecules becomes more effective; thus, these heavy molecules coalesce into a liquid. This process continues until a pressure (B) is reached where a maximum amount of liquid is formed. Further reduction in pressure permits the heavy molecules to commence normal vaporization, the process whereby fewer gas molecules strike the liquid surface; this causes more molecules to leave than to enter the liquid phase, until complete vaporization of the liquid occurs again (C).

Wet Gas

Behavior of a wet gas is shown in Fig. 43, where temperature is above the critical condensing temperature of the gas mixture. Therefore, a reduction of pressure (from A to B) will not cause liquid condensation. Passage of gas from existing temperature to stock tank conditions where the temperature is lower, however, will result in the formation of liquid. This is caused by a sufficient decrease in the kinetic energy of heavy molecules with temperature drop and their subsequent change to liquid through the attractive forces between molecules.

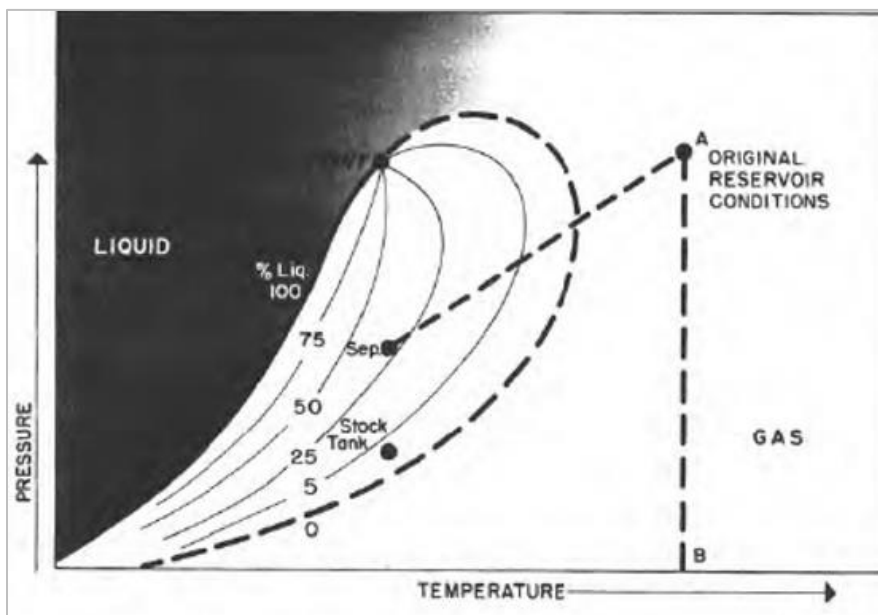


Fig.43. Phase diagram of wet gas. (Courtesy World Oil- March, 1953)

Dry Gas

Behavior of a dry gas is illustrated by the phase loop in Fig. 44. The temperature is above the critical condensing temperature of the gas mixture and, like the wet gas, will not condense to a liquid with pressure drop (from A to B). Passage of dry gas to surface conditions will not, however, result in a condensation of liquid through lack of sufficient heavy material in the mixture. Kinetic energy of the mixture is so high and attraction between molecules so small that none of them coalesce to a liquid at stock tank conditions of temperature and pressure.

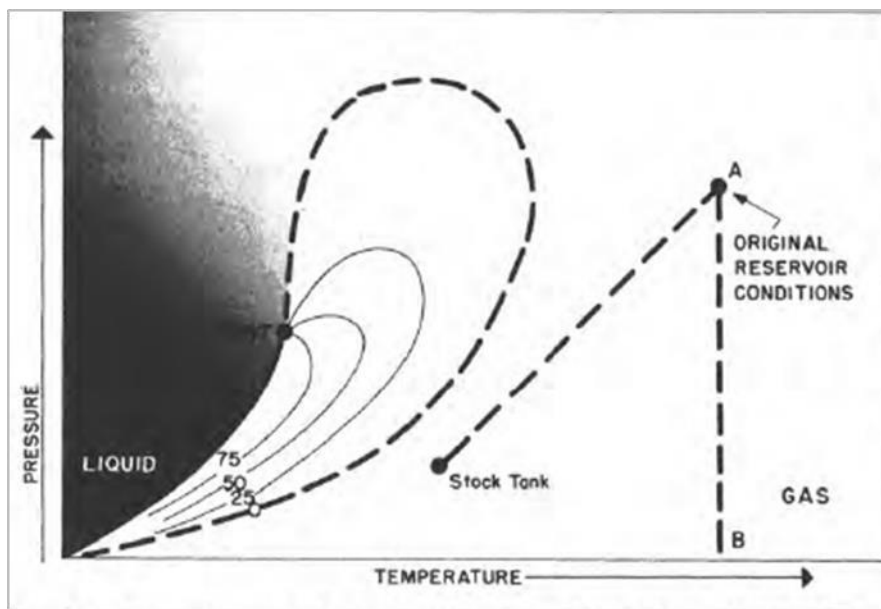


Fig.44. Phase diagram of dry gas. (Courtesy World Oil- March, 1953)

Testing Fluid Properties and Behavior

As reservoir pressure is reduced and liquid and gas phases are formed, one or the other of the two phases is produced differentially to some degree because of variations of permeability of the rock to gas and oil as fluid saturations change (See Chapter 2). Hydrocarbon analysis of the composite production therefore changes from that of the original material in place in the reservoir. Thus, behavior of reservoir fluids during production operations cannot be described completely by what their behavior would be under equilibrium conditions as previously described. Laboratory measurements are needed on phase behavior of reservoir fluid samples for conditions of change where liquid and gas separate both differentially and under equilibrium conditions to solve production problems involving separation under both conditions.

The practical approach to the study of reservoir fluid behavior as practiced by the industry is to anticipate pressure and temperature changes in the reservoir and at the surface during production operations; then measure by laboratory tests the changes occurring to reservoir fluid samples.

Oil Sampling and Testing

Two general methods are used to obtain samples of reservoir oil for laboratory examination purposes; (1) by means of subsurface samplers and (2) by obtaining surface samples of separator liquid and gas. Separator samples of oil and gas are recombined in the laboratory in proportions equivalent to the gas-oil ratio measured at the separator.

Data usually obtained include: (1) original reservoir temperature and pressure; (2) pressure-volume relations at one or more temperatures, one of which is always the reservoir temperature (taken as shown in Fig. 45); (3) effects of variation of surface separator pressure on amounts of gas liberated and shrinkage of oil resulting from such separation process; (4) differential gas liberation and oil shrinkage data, taken in the manner shown in Fig. 46; (5) density or specific volume of reservoir

fluid; (6) viscosity relation of reservoir oil at reservoir temperature and at pressures ranging from original reservoir pressure to atmospheric pressure and viscosity of stock tank oil; (7) hydrocarbon and orsat analyses of the mixture as it existed originally in the reservoir; and (8) ASTM distillation analyses of residual oil.

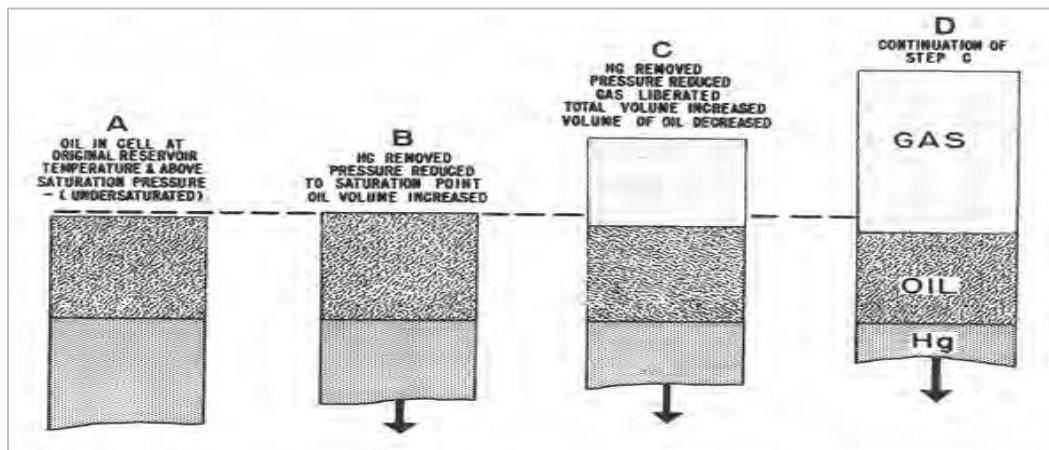


Fig. 45. Laboratory equilibrium liberation (P.V.T) of gas from oil. (Courtesy World Oil- April, 1953)

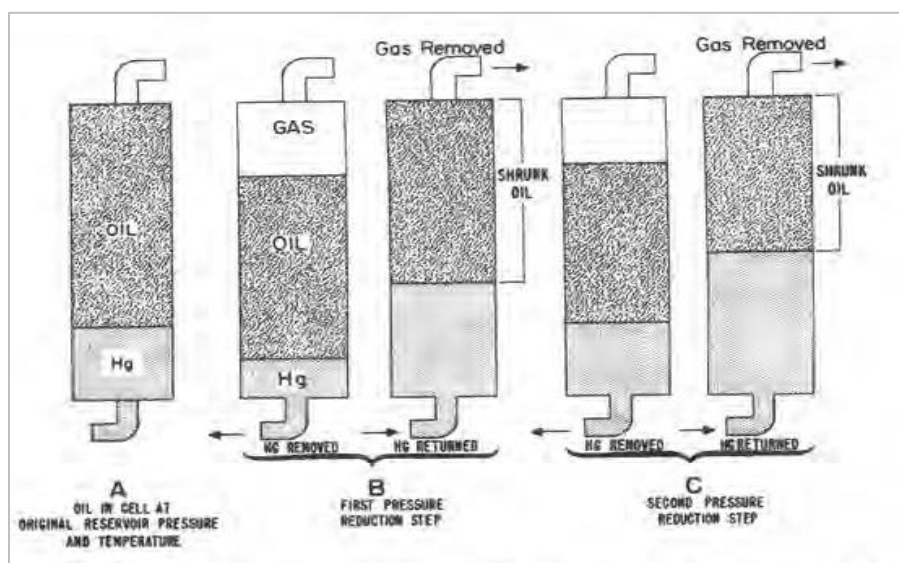


Fig.46. Laboratory differential liberation of gas from oil. (Courtesy World Oil- April, 1953)

Equilibrium and Differential Data of Oil Samples

If liberated gas is permitted to stay in direct contact with a liquid sample (Fig. 45), a different volume of gas will be liberated down to a given pressure, then would be released if the gas were removed from contact with the liquid as it is liberated. The remaining liquid is likewise different in the opposite direction; thus, oil shrinkage is different. Differential liberation is that process which takes place when the gas is removed as it is formed incident to a drop in pressure at constant temperature (Fig. 46). Each type of liberation process is encountered to some degree at one time or another in the production of petroleum deposits; therefore, both processes for a given oil sample must be investigated to provide data for a complete reservoir study.

A comparison of equilibrium and differential shrinkage of a low shrinkage oil under reservoir conditions as pressure drops is presented in Fig. 47. This shows that, under equilibrium conditions, a greater quantity of heavy components is progressively pulled into the gas by the light gas components; thus, oil shrinkage is greater. Lower shrinkage by differential liberation under these conditions is caused by gas being removed as it is formed, thereby preventing further attraction of light gas molecules to heavy liquid molecules, and minimizing the quantity of liquid pulled into the gas phase.

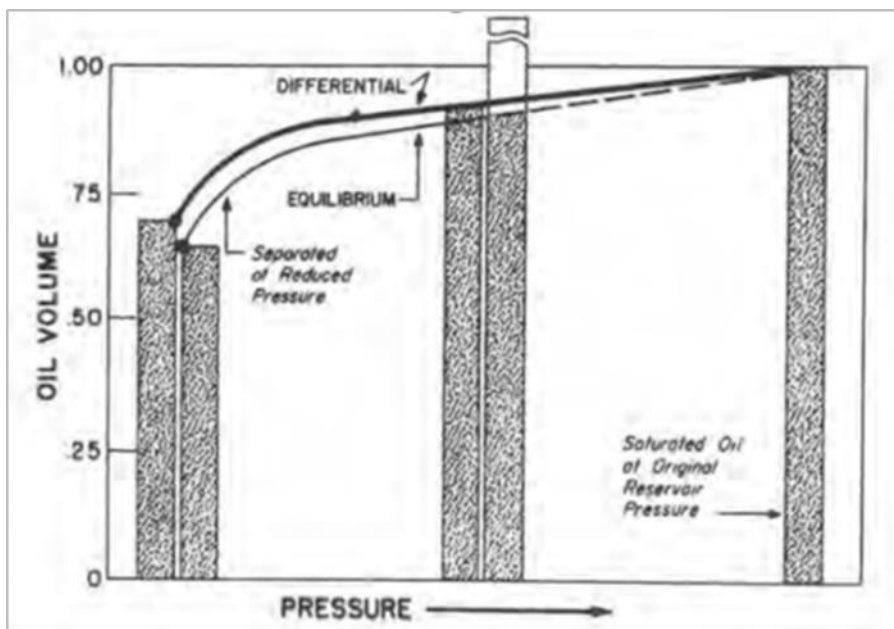


Fig. 47. Equilibrium and differential shrinkage of low shrinkage oil. (Courtesy World Oil- April, 1953)

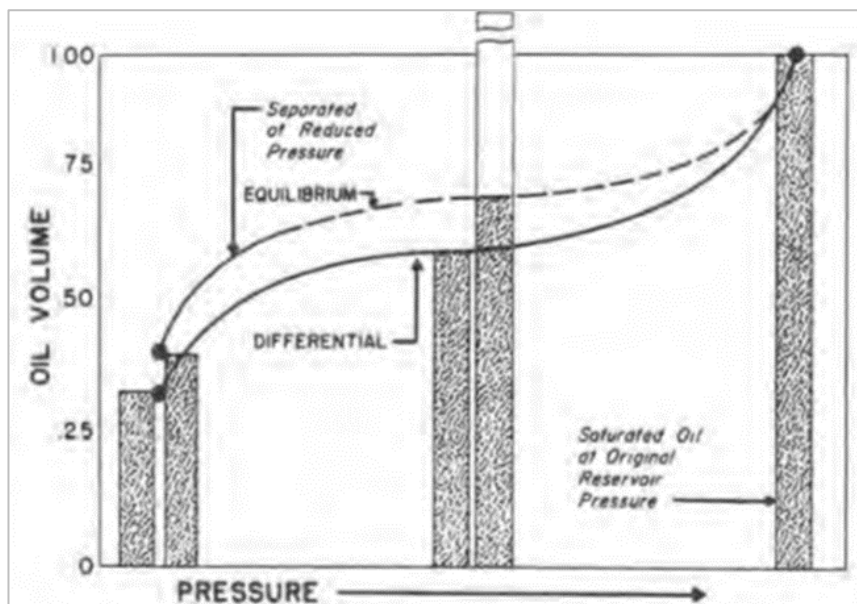


Fig. 48. Equilibrium and differential shrinkage of high shrinkage oil. (Courtesy World Oil- April, 1953)

A comparison between equilibrium and differential shrinkage of a very high shrinkage oil is presented in Fig. 48. In this case, the difference is reversed from that of low shrinkage oil. More gas is formed in the high-pressure range than with low shrinkage oil. This is caused by a large quantity of intermediates being pulled into the gas phase (through great attraction to the densely spaced light gas molecules and through high kinetic energy of the intermediates). Once the large quantity of intermediates is removed from the system by differential liberation, they have no further influence on gas liberation and oil shrinkage; therefore, oil shrinkage remains high through lower pressure ranges. If the gas is not removed, as in flash or equilibrium liberation, some intermediate gas molecules may condense because their attraction to light gas molecules is reduced as pressure drops and the light gas molecules become farther apart; thus, vaporizing tendency of high shrinkage oil may be reversed until shrinkage is less under equilibrium conditions than under the differential process.

Shrinkage curves of both low and high shrinkage oil illustrate that, near atmospheric temperature and low-pressure conditions, shrinkage of oil greatly increases and presents a problem if maximum liquid volume is to be produced to the stock tank as saleable material.

Oil of all degrees of shrinkage will shrink less to the stock tank if the material is first passed to a separator at some elevated pressure and free gas, formed down to that pressure and temperature, is separated. Also, there is an optimum separator pressure condition where minimum shrinkage of oil is obtained. This will be discussed further in Chapter 10.

Gas Sampling and Testing

Free gas is classified into three general types according to phase behavior upon reduction of temperature or pressure (or both) as illustrated by the phase diagrams in Figs. 42, 43 and 44. The types are termed retrograde condensate gas, wet gas and dry gas, respectively, and may apply to gas deposits that are either associated or non-associated with oil deposits.

There are two general methods for sampling gas wells. The first utilizes the full-scale field separator and involves recombination of separator material in the laboratory for testing. The second method uses a tubing head (or line probe) which diverts a portion of produced material to a mobile small-scale separator, portable laboratory or test car which involves performing part of the tests in the field on large samples. Use of the latter method is generally limited to detailed testing of retrograde condensate gas reservoirs.

Information concerning the characteristics and behavior of gas most frequently needed for work with gas reservoirs depends upon the types of gas considered and the nature of the problem. If the problem at hand involves retrograde condensation as pressure drops, the information needed may become very complex and may require numerous tests and measurements. If the problem involves wet gas (where no retrograde condensation occurs but liquid is recovered in separators) or dry gas (where no liquid is condensed in either the reservoir or separator), then the information needed may be considerably less complex.

Retrograde condensate gas material will be described here. It is important that enough tests be made on gas produced from gas reservoirs to identify the gas positively as to its retrograde characteristics in order for the operator to guard against losing economically recoverable

liquids. Laboratory data of condensate gas reservoir fluids include data on (1) the quantity, hydrocarbon analysis and specific volume of original material in the reservoir, (2) the quantities of vapor and condensed liquid in the reservoir at subsequent reduced reservoir pressures and (3) the complete surface separation history as reservoir pressure decreases, including optimum separation data together with hydrocarbon analyses of separator gas, separator liquid, stock tank gas and stock tank liquid.

Equilibrium and Differential Data of Gas Samples

If pressure is dropped on a gas sample by increasing the volume without withdrawing gas, a different volume of liquid will drop out by retrograde condensation than will occur if pressure is dropped by removing gas without changing the volume of the remainder of the sample.

The first process, illustrated in Fig. 49, is termed equilibrium condensation. The latter process, illustrated in Fig. 50, is termed differential condensation and is analogous to production from a closed reservoir.

A comparison of equilibrium and differential condensation of a retrograde gas as measured in the laboratory is presented in Fig. 51. More liquid condenses under equilibrium conditions than under differential conditions because a greater quantity of gas remains in the system in the equilibrium process from which heavy components may condense as pressure drops.

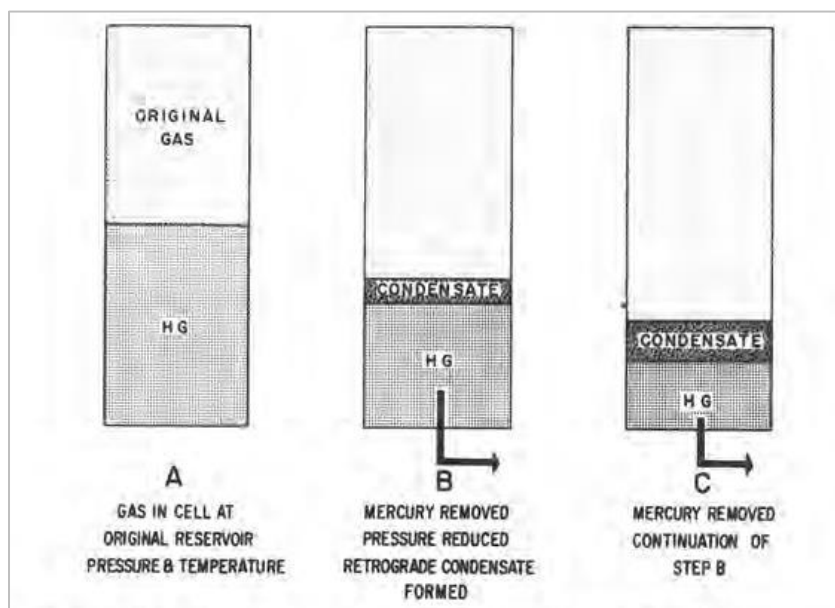


Fig. 49. Equilibrium retrograde condensation of liquid from gas. (Courtesy World Oil- April, 1953)

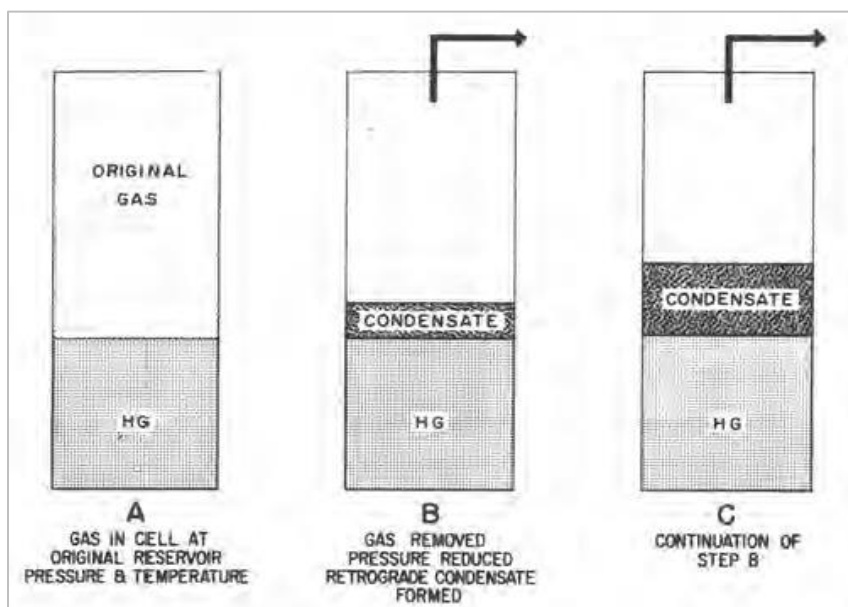


Fig. 50. Differential retrograde condensation of liquid from gas. (Courtesy World Oil- April, 1953)

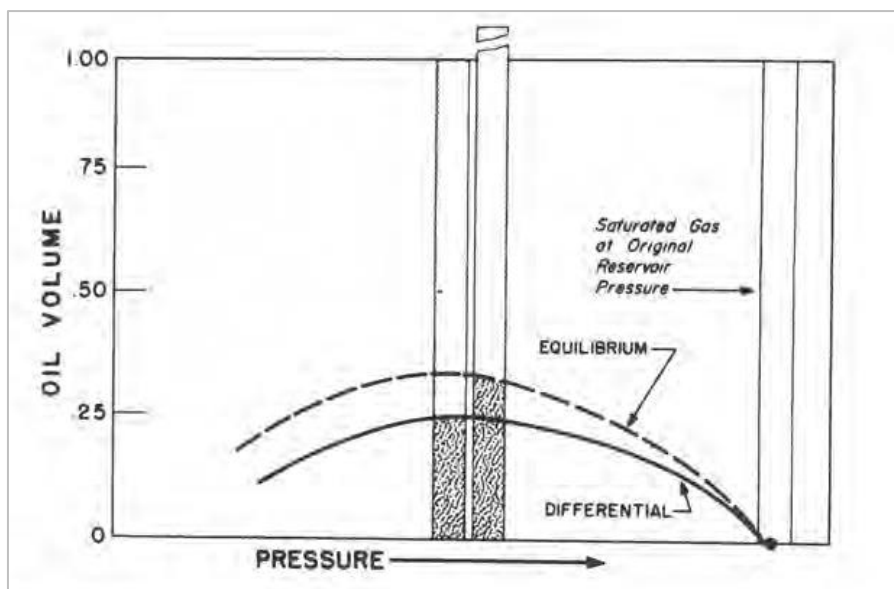


Fig. 51. Differential and equilibrium condensation of liquid from gas. (Courtesy World Oil- April, 1953)

Condensate Gas Problems

The important problem in condensate gas reservoir material lies in the change of composition of produced material brought about by retrograde condensation in the reservoir of the heavier hydrocarbon components as reservoir pressure drops during production operations. Retrograde condensation characteristics drastically affect desirable operations

because it is the condensate material that provides a large part of the income from the produced gas. Ultimate loss of income results if liquids are allowed to condense in the reservoir to form a non-recoverable liquid saturation. Because this liquid saturation is small in percent of reservoir pore volume, its displacement from the reservoir other than adjacent to the wellbore may be difficult to accomplish by conventional production of reservoir gas.

The problem of surface separation is involved in the production of gas just as in oil production, whether reservoir conditions at the time of production are at the original or some reduced pressure. It is necessary, therefore, to establish proper separation conditions to recover a maximum amount of liquids in the separator. Obtaining maximum profits from production of gas reservoirs requires solution of these problems. This subject is discussed in detail in Chapter 12.

Chapter 4: Distribution of Fluids in the Reservoir

Nearly every man has at some time measured the API gravity of oil. Yet in nearly every case, he has had some difficulty in accurately reading the hydrometer used to make this measurement because the oil rises above the level of the sample at the point of contact with the glass stem of the hydrometer. It is little realized that this difficulty in reading the hydrometer results from the same physical characteristic which determines the relative ease with which oil moves in and is produced from tiny pore channels in the reservoir rock. This effect is also responsible for the manner in which gas, oil and water distributions occur in the reservoir rock. The effect is caused by a combination of (1) wettability of the glass to oil and (2) tension in the surface of the oil between oil and air. The curved surface at the edge of the liquid where it contacts the glass surface of the hydrometer stem and which blurs the appearance of the liquid level is called a meniscus.

Wettability

Adhesion is the quality which causes particles of a given material to cling together. If a glass rod is dipped in water and removed, the rod will be wet, showing that some water is more adhesive to glass than to water itself (Fig. 52). The glass rod dipped in mercury will be dry when removed, showing that mercury is more cohesive to itself than adhesive to glass. Water will not adhere to a greasy glass rod, but a clean brass or zinc rod will be wet by either water or mercury because of the adhesion between these materials and the liquids. A liquid, therefore, wets a solid when adhesion of the liquid to the solid is greater than cohesion of liquid particles for each other.

Surface Tension

Surfaces of liquids nearly always are blanketed with what acts as a thin film. Although this apparent film possesses little strength, it nevertheless acts like a thin membrane and resists being broken. This is believed to be caused by attraction between molecules within a given material, as shown in Fig. 53. Thus, there exists a tension in the surface of a liquid which is called surface tension. If carefully placed, a needle will float on the surface of water, supported by the film even though considerably denser than water, and will actually be suspended below the surface by the film.

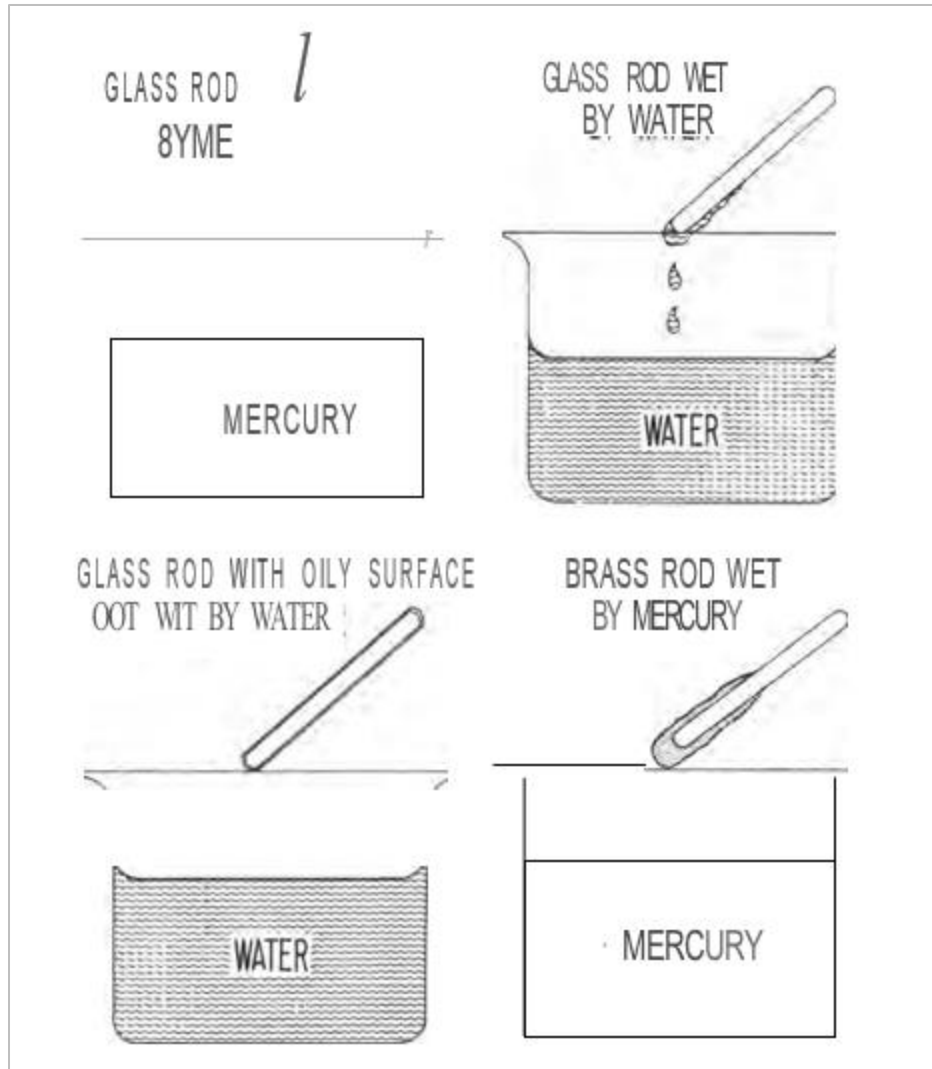


Fig. 52. Wettability depends on wetting fluid, type of material, and condition of surface of the material.

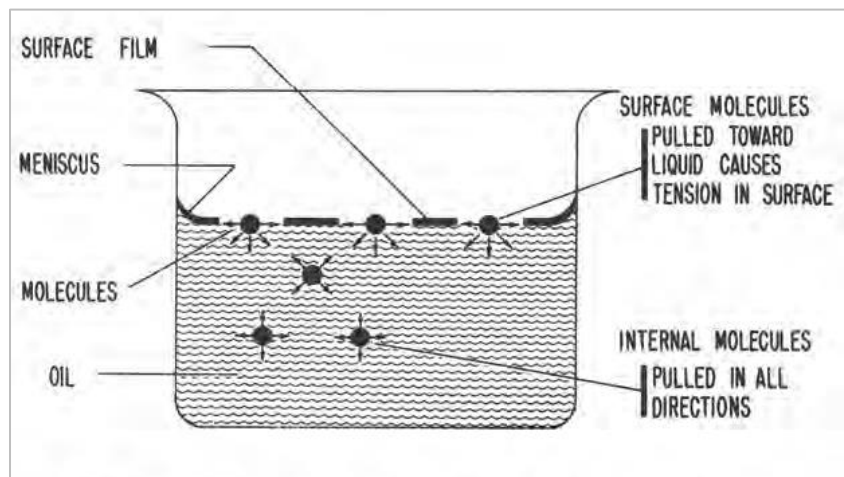


Fig.53. Apparent surface film caused by attraction between molecules of a liquid.

Capillary Pressure

Some effects of wettability and surface tension are shown in Fig. 54. A drop of water that wets the surface will spread out against tension in the surface film. A drop of mercury that does not wet the surface will be held by surface tension, although the mass of the mercury tends to flatten the droplet.

If the open end of a glass capillary tube is inserted into water, the combination of surface tension and wettability of tube to water will cause water to rise in the tube above the water level in the container outside the tube (Fig. 55). If the capillary tube is inserted into mercury, lack of wettability of the glass capillary tube to mercury, together with the surface tension of the mercury, will prevent the mercury in the tube from rising even to the fluid level in the container.

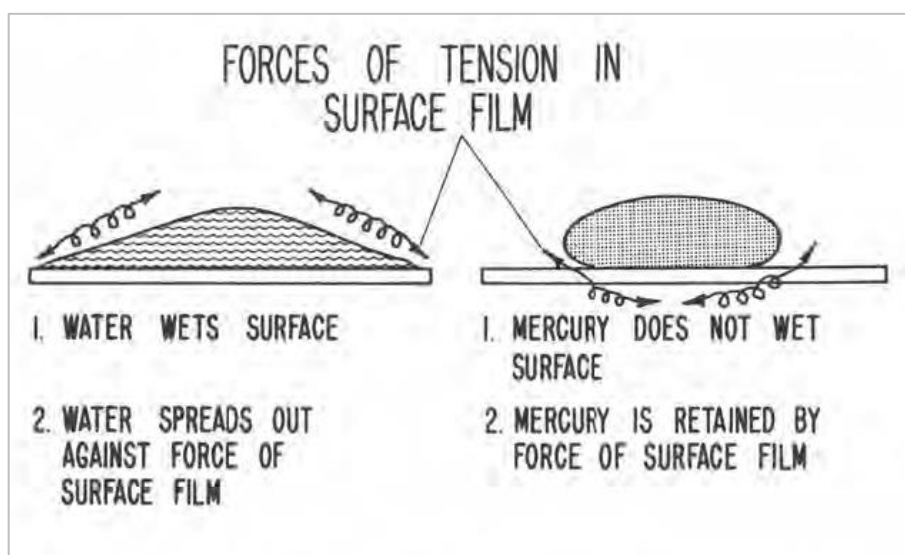


Fig. 54. Effects of wettability and surface tension on action of drops of water and mercury on surface.

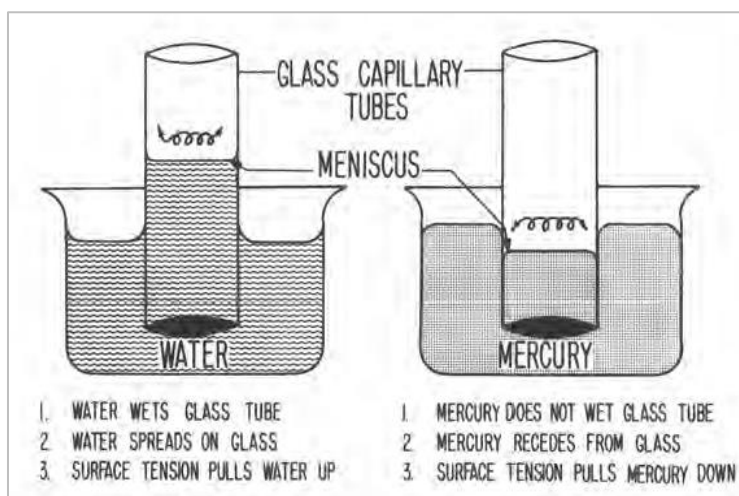


Fig.55. Rise of water and depression of mercury in glass capillary tube.

Size of the capillary tube influences the height to which water will rise or the depth to which mere will depress. Water will rise higher in smaller tubes, as shown in Fig. 56. The same effect occurs in the case of oil; although oil is lighter, it cannot be pulled as high because surface tension in oil is less.

To understand better the reason water rises in a capillary tube, let us further consider the surface tension in the liquid. This film resists being bent just as a plank does. If a plank were placed across two sawhorses and a weight suspended from the plank, the plank would bend; if a greater weight were suspended, the plank would bend more. This is similar to what happens when water wets the capillary tube and is pulled up in the tube by liquid wettability and adhesion of the liquid for the tube. At the same time, water forms a weight that pulls the film down in the center of the tube (just as the weight suspended from the plank).

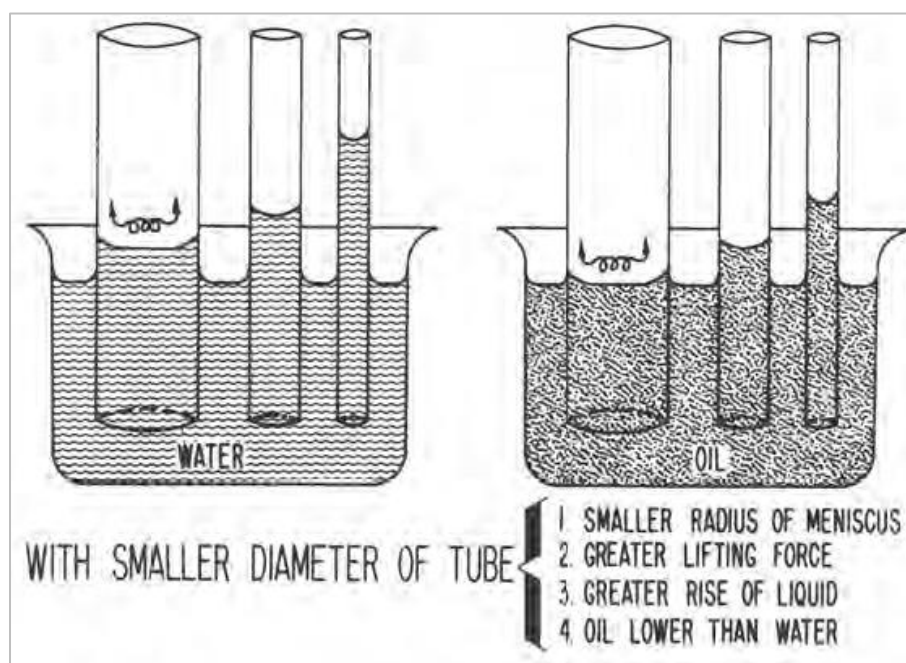


Fig. 56. Effect of size of capillary tubes on the height the liquid will be raised in tube.

Material will rise higher in a small tube than a large one because of the difference in amount of pull-down on the film by the weight of water as compared to amount of pull-up by the wetting action of water to tube. For smaller tubes, the amount of contact of film with glass reduces in proportion to reduction in circumference of the tube. This reduction in contact, and thus pull-up, is not as much as reduction in the volume of water contained by the smaller tube up to a given height. Because the available lift force on the water does not decrease in proportion to the decrease in volume of water it lifts, the force pulls the water higher until it is balanced again at a greater height by total weight of the water. But here another effect occurs. The bending of the film occurs because of the weight of water suspended per unit area of film. The weight of water lifted for a given area is greater in the smaller tube because the water is raised higher. Thus, the liquid is raised higher, and the film bent more in the smaller tube.

Visualize the bent film from another standpoint. The film is bent downward because a partial vacuum is created beneath the film by the suspended water (pulling downward on the film) and

the surface tension in the film (resisting the downward pull). Pressure is less on the lower (convex) side than on the upper (concave) side of the film. This difference in pressure across the film is known as capillary pressure (Fig. 57). Capillary forces are, therefore, formed as a result of a combination of wettability and surface tension effects.

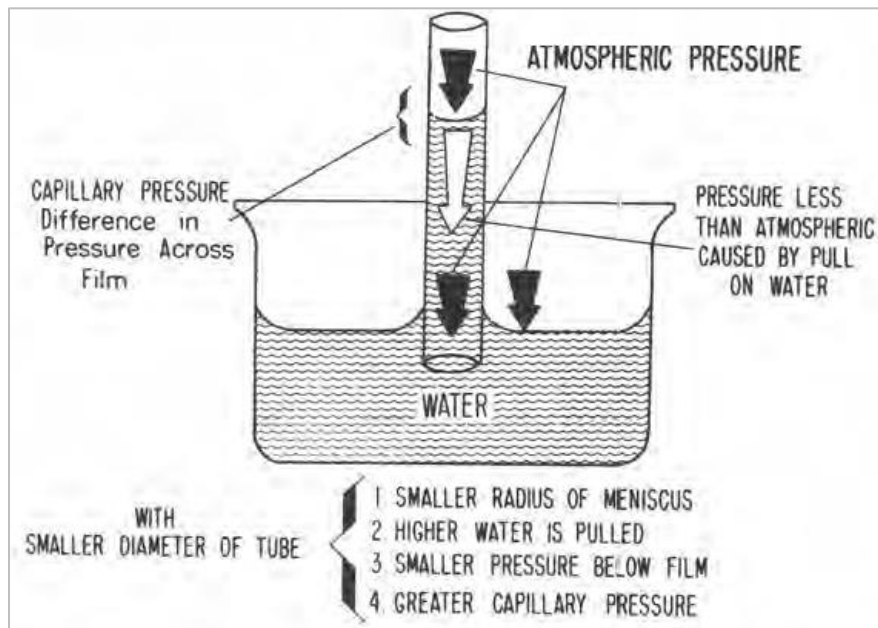


Fig.57. Capillary pressure across surface film in capillary tube.

Distribution of Fluids

If oil, water and gas were placed in a bottle, the boundary between water and oil would be level; the boundary between oil and gas would be level, with the gas located on top, the oil between and the water below. This distribution would naturally result from the difference in densities of the three materials.

Water, oil and gas were placed in the same glass bottle after the bottle had been filled with sand, the distribution of the water, oil and gas would be in the same order (water below, oil between and gas above). However, the contacts between the oil and water and the oil and gas would be quite different from the case where no sand was present. The reason for this is that now the gas, oil and water exist in spaces that are capillary in size.

Wettability, surface tension and density differences between the three fluids combine to alter the manner in which the fluids occur; the forces present between the fluids in the capillaries caused by these factors are called capillary forces.

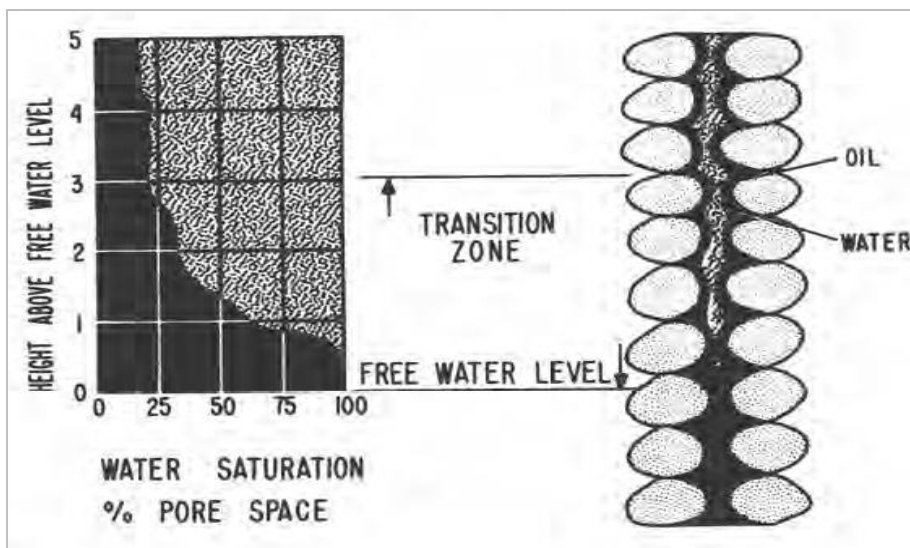


Fig. 58. Effects of height above free water level on connate-water content in oil sand.

In marine sediments, the preferential wetting phase is usually water (probably because of its initial association with water). As oil moved into the sand, water was displaced but left a film along the sand grain surface separating the sand grain from the oil. At any point where the film became broken, contact between the sand grain surface and oil in the absence of water might have allowed the sand at that point to become oil-wet. In the water wet oil reservoir, some water is held along the sand grain surfaces throughout the reservoir, as illustrated in the enlarged pore channel shown in Fig. 58. Amount of water present in the pores varies from 100 percent at points below the oil zone of the reservoir, to lower and lower percentages at points higher in the oil zone. This is caused by the decreasing radius of the film between oil and water at higher heights. The higher the water is pulled above the 100 percent water level, the greater the capillary film will be bent to suspend the water.

As the radius of the bent film becomes smaller, or as the film bend increases due to greater capillary forces, the water fits farther back into the cracks and crevices between sand grains; because of the shape of grains and film, the quantity of water diminishes with reduction in radius of the film at greater heights. The schematic diagram in Fig. 58 shows the change in water saturation with height. Of great importance is the transition zone of saturation of water and oil from a point of 100 percent water upward in the sand, to some point above which water saturation is fairly constant. Theoretically, the amount of water will continue to diminish with height above the free water level; however, it has been found in practice that water saturation becomes fairly constant in uniform sands at points above the transition zone. Therefore, the term "irreducible minimum water saturation" has sometimes been applied to the percent of water by volume occurring in pore spaces of reservoirs. This water is also referred to as "connate" or "interstitial" water.

It was pointed out earlier that sand grains are irregular, making pore channels between the grains irregular. Sands in different beds or formations differ even more. Other things being equal, pore channels in a lower permeability sand will be smaller; this illustrates an important trend regarding water content of different permeability sands, as shown in Fig. 59. For a given height above the free water level, capillary pressure will be the same in two pores of different size. Therefore, the

film between water and oil will have the same curvature for equal pressure; consequently, the amount of water occurring in the crevice will be about the same. More oil is contained in the larger pore space, however, the percent of water in the small pore will be greater than in the larger. In general, the lower the permeability of a given sand, the higher will be the connate-water fraction within the sand.

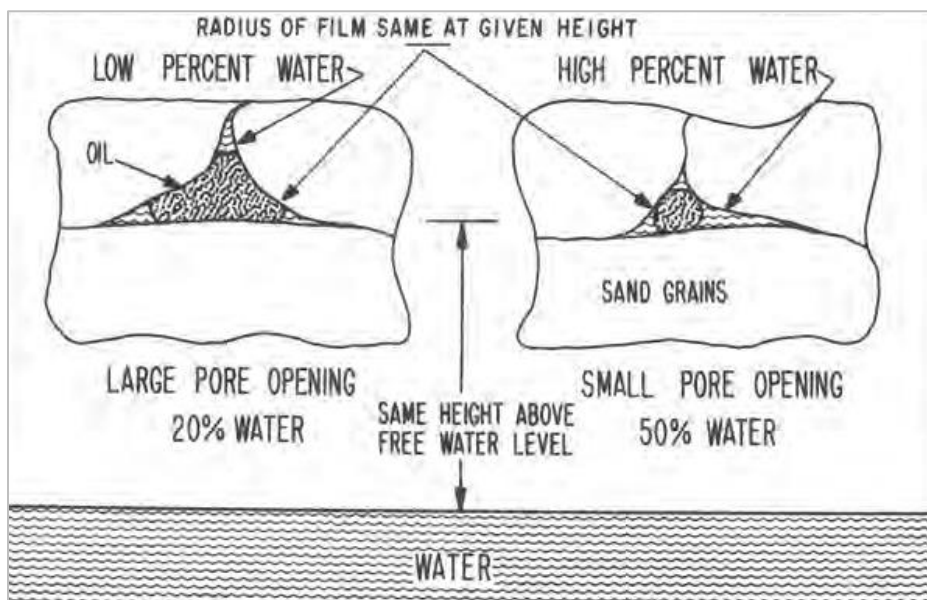


Fig. 59. Effect of pore size and shape on connate-water content.

The zone of transition between oil and water will be thicker vertically than that between water and gas for a given texture or permeability of reservoir rock, as shown in Fig. 60. Difference in weight between water and gas is great, and water tends to pull down and seek its own level to a greater extent; however, difference in weight between water and oil is smaller, and water tends to pull down below the oil to a lesser degree. The difference in weight between oil and gas is likewise, greater than between oil and water; therefore, the transition zone between oil and gas (gas-oil contact) is not so thick as the transition zone between oil and water (water-oil contact).

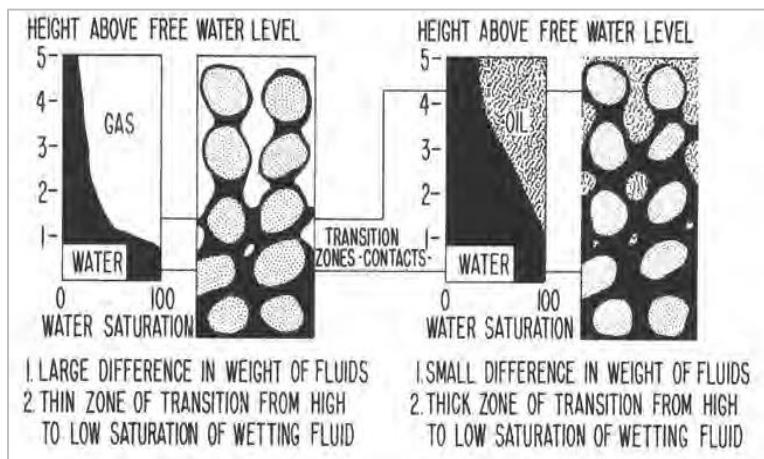


Fig. 60. Effect of weight of fluids on thickness of transition zones.

If permeability of the sand is very low, the zones of transition between water and oil, and oil and gas will be spread out more vertically, or be thicker, than those occurring in high permeability sands. This is true because low permeability sands have some smaller pore openings which cause water to be pulled higher above the free water level than would be the case with high permeability sand which has larger pore openings. Therefore, the nature and thickness of the transition zones between water and oil, oil and gas, and water and gas are influenced by several factors, among which are the uniformity, permeability and wettability of the rock, and the surface tension and density differences between the fluids involved.